

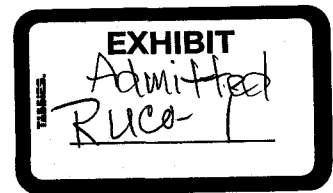


Transcript Exhibit(s)

Docket #(s): RE-00000C-94-0165

Exhibit #: RUC01, RUC02, AETPC01, AETPC02,

NAVI



BEFORE THE ARIZONA CORPORATION COMMISSION

**IN THE MATTER OF)
COMPETITION IN THE)
PROVISION OF ELECTRIC)
SERVICES THROUGHOUT)
THE STATE OF ARIZONA)**

DOCKET NO. U-0000-94-165

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

**Submitted on Behalf of
The Residential Utility Consumer Office**

January 21, 1997

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Residential Utility Consumer Office

Executive Summary

This testimony is offered in response to Docket No. U-0000-94-165 on behalf of the Arizona Residential Utility Consumer Office (RUCO). The purpose of this testimony is to provide the Arizona Corporation Commission (ACC) with 1) public policy recommendations of key issues related to the calculation, sharing, and recovery of stranded costs, and 2) presentation of the "retail generation service" methodology for computing stranded costs. To illustrate RUCO's position, this testimony provides an initial calculation of stranded costs for Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), and the Salt River Project (SRP).

In response to the ACC's Eleven Policy Questions in this docket, the following are the conclusions reached in this testimony. This testimony advocates use of the "administrative valuation approach" for calculating stranded costs. This approach compares projections of the utility's revenues for electric generation if generation prices were deregulated, and projections of the utility's revenues for electric generation if generation prices were continued to be regulated based on the utility's embedded costs of generation. In calculating stranded costs, total *potentially* stranded costs (strandable costs) should be computed. An estimation of the market price for retail generation services is necessary to produce projections of the utility's revenues for electric generation. Therefore, the market price of power should be determined based on the average retail cost of power in the region to serve a particular load based on its load factor and other seasonal characteristics. Developing estimates of the market price of power should include the wholesale price, but should be based on the total retail price for generation services to the customer, which is equal to wholesale price plus a retail margin.

Stranded costs should include the following categories of costs that are currently being incurred by utilities: generation assets and generation operations and maintenance (O&M) costs, purchase power agreements, fuel contracts, generation-related regulatory assets and liabilities, and generation-related A&G. Stranded costs should be calculated using a time period of at least 15 years, and perhaps as much as 25 years, depending on the expected remaining operational life of the generation resources of a particular utility. The amount of stranded cost recovery from ratepayers should be calculated administratively and trued-up annually (or at least bi-annually) to account for the actual retail market prices of generation. The Affected Utilities should bring the embedded cost of generation closer to the market price for generation through appropriate mitigation measures *before* Arizona takes steps towards allowing recovery of stranded costs. The most important mitigation measures utilities should take are those that focus on cost reduction.

If there are stranded costs, ratepayers and shareholders should share in paying for stranded costs. While the appropriate percentage of this sharing should be determined by the ACC, an initial 50/50 split is a reasonable approach. Payment by all ratepayers should be made through a non-bypassable, nondiscriminatory "wires" charge or competition transition charge (CTC) which would tie the collection of stranded generation costs to the continued use of transmission and/or distribution service. In determining the CTC, the economic generation and generated ancillary services should be separated from the uneconomic or stranded generation costs. The CTC stranded cost recovery mechanism should be administered to *all* retail customers in a distribution utility's service territory. Therefore, both customers on the standard offer service and those customers in the competitive market purchasing electric generation service from alternative suppliers should pay for stranded costs on the same basis.

The time frame for stranded cost recovery should be determined prior to commencing the recovery process. I recommend that the time frame not extend past the end of the transition period defined by the Competition Rules, i.e., January 1, 2003, unless it is determined during a true-up in 2002 that a large credit is due ratepayers because stranded costs are strongly negative. In that case, negative stranded cost recovery would have to continue for many years beyond 2003.

While stranded costs are being recovered, there should not be a rate freeze; there should be a rate reduction. However, a price cap on the generation rate is necessary during the transition to completely unregulated generation markets in order to protect ratepayers from any adverse effects of the unregulated generation market during this time period. The rate cap should be at or below the level that rates would have been under continued regulation. The rate reduction should result from setting the price of the standard offer service at a market-based price for retail generation services.

This testimony offers initial estimations of the magnitude of strandable generation costs that APS, SRP and TEP have. These estimations were reached through use of the Tellus stranded cost model (SCM). The Tellus SCM is a spreadsheet model which performs three independent analyses: an unbundling analysis, a market price analysis for retail generation services, and projections of potentially strandable costs over a specified period of time. Using utility-specific data from the most recent FERC Form 1, the model develops an estimate of a utility's unbundled costs of generation, transmission, distribution and customer costs that are reflected in the utility's average retail rate. The unbundled cost of generation, or retail generation services, is then compared to a market price for retail generation services in order to estimate potential stranded costs.

Under a Basecase APS, SRP, and TEP will have strandable costs over the period 1998-2020 of negative \$838 million, negative \$3.0 billion, and positive \$513 million in 1998 present value dollars, respectively. If the calculation period is reduced to only 15 years (1998-2012), APS, SRP, and TEP will most likely have strandable costs in the range of positive \$102 million, negative \$834 million, and positive \$779 million, respectively, in 1998 present value dollars. Thus, it is concluded that of these three utilities, only TEP

may have any significant level of positive strandelable costs. This is because the ratepayers have already paid off any uneconomic costs that previously existed on the APS and SRP systems. This implies that unless a negative stranded cost recovery charge is put into place for APS and SRP once retail competition begins, ratepayers may pay more for electricity over the subsequent 15 years and longer, under retail competition, than they would have paid if regulation were continued. It is also very important to note that the Basecase results indicate that after about 2003, the expected average retail price of power in the unregulated market will exceed the expected regulated price of generation for APS and SRP. This implies that ratepayers will likely pay more under retail competition after 2003 on an annual basis, than if regulation were continued. This forecast graphically illustrates the fact that if a negative stranded cost recovery charge is not put into place for APS and SRP ratepayers for up to 10 years, or there are no substantial productivity improvements as a result of competition, ratepayers may not benefit from retail competition.

However, RUCO anticipates that competition will benefit consumers because technological innovations and operational efficiencies will occur in the open market. Furthermore, the risk of paying for future operational efficiencies has been eliminated. Additionally, during the transitional period, under RUCO's proposal, residential consumers will be protected by a rate cap, a true-up, and the potential amortization of negative stranded cost.

In contrast, for TEP the ACC should establish a stranded cost recovery charge based initially on 50 percent of initial estimates of TEP's strandable costs reported in this testimony. The ACC should also investigate in TEP's utility-specific stranded cost docket the reasons for the existence of TEP's strandable costs, and should determine whether a lower percentage than 50 percent of TEP's strandable costs should be charged to ratepayers. If the ACC decides that ratepayers should pay for less than 50 percent of TEP's stranded costs, then the stranded cost recovery charge should be appropriately adjusted. Of course, the ACC should also true-up TEP's stranded cost recovery charge either annually, or at least bi-annually, as actual retail market price data becomes available. Any recovery of stranded costs by TEP should end by January 1, 2003, so that at least there is a probability that the rates for ratepayers in TEP's service territory will be lower after this date than they would have been under regulation.

Based on the findings and conclusions reached in this testimony, it is recommended that the Electric Competition Rules be modified regarding stranded costs. Specifically, it is recommended that changes be made to the Rules regarding the definition of stranded costs in Section R14-2-1601 (8). Changes should also be made to Sections A, B, H, I, J and L of R14-2-1607. No recommendations are offered for changes to Sections C, D, E, F, G, or K of R14-2-1607. Specific changes in the wording of each section of the Competition Rules is provided at the end of Section 6 of this testimony.

Additionally, it is recommend that the ACC follow-up this generic docket with utility-specific proceedings as provided for under the current Competition Rules this

would allow the enclosed initial estimates of stranded costs to be refined. One reason this is necessary is because the ACC has not yet reviewed and ruled on the issue of what the unbundled rates for the Affected Utilities should be. Yet, the proper calculation of stranded costs should include the final ACC ruling on the magnitude of the generation portion of current rates as a starting point. A second reason is that these initial calculations of stranded costs have not had the benefit of information that would have obtained through discovery that might allow the refinement of certain input assumptions used in calculations of stranded costs herein.

1. INTRODUCTION AND QUALIFICATIONS

1

2

3 Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

4 A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11
5 Arlington Street, Boston, MA 02116-3411.

6

7 Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL
8 BACKGROUND.

9 A. I hold a B.S. in Physics and Philosophy from M.I.T., an M.S. in Physics from
10 Columbia University, and a Ph.D. in physics from Columbia University. Currently
11 I am a senior research director at Tellus Institute, as well as executive vice-
12 president of the Institute. I am also the manager of the Institute's Electricity
13 Program.

14

15 Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

16 A. Tellus Institute is a non-profit organization specializing in energy, natural resource,
17 and environmental research. Within Tellus Institute, the Energy Group focuses on
18 energy and utility research areas which include demand forecasting, conservation
19 program analysis, electric utility dispatch and reliability modeling, least-cost utility
20 planning and integrated resource planning, avoided cost analysis, financial analysis,
21 cost of service and rate design, non-utility generation issues, bidding systems,
22 incentive regulation, cost of capital analysis, and utility industry restructuring.

1 Q. PLEASE ELABORATE ON TELLUS' EXPERIENCE WITH ELECTRIC
2 UTILITY SYSTEM SUPPLY PLANNING.

3 A. The Energy Group has had wide experience assessing utility system supply options
4 on both a service area and a regional basis. These assessments have encompassed
5 all types of generation plant, transmission plant, purchases of capacity and energy,
6 fuel purchases and contracting, central station district heating and decentralized
7 cogeneration plants, and alternative sources of energy such as wind, biomass, and
8 solar energy connected to electricity grids. These assessments have dealt with the
9 technical, economic, environmental, regulatory, and financial aspects of supply
10 planning, including the relationships between supply planning, load forecasting,
11 rate design, and revenue requirements. Tellus Institute also has reviewed the
12 prudence of many past supply planning decisions by utilities.

13
14 Q. PLEASE REVIEW YOUR EXPERIENCE IN THE AREA OF UTILITY
15 PLANNING.

16 A. Power supply system modeling and integrated resource planning has been a major
17 focus of my activities for the past 16 years. My research and testimony in this area
18 began in 1980, and I have testified in numerous cases involving generation
19 planning and the integration of demand and supply technologies on a least-cost
20 basis. For example, I submitted extensive generation planning testimony in the
21 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the
22 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I
23 prepared a major report for the Alabama Attorney General's Office entitled "Long-

1 Range Capacity Expansion Analysis for Alabama Power Company and the
2 Southern Company System," and I filed testimony in Docket No. 18337 before the
3 Alabama Public Service Commission. In addition, I testified on the excess capacity
4 issue regarding Susquehanna unit 1 in the 1983 Pennsylvania Power and Light Co.
5 Rate Case (No. R-822169). In 1987, I testified before the Federal Energy
6 Regulatory Commission on NEPOOL's Performance Incentive Program on behalf
7 of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989,
8 I testified before the Pennsylvania Public Utility Commission on excess capacity
9 and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear
10 unit. This work was performed on behalf of the Pennsylvania Office of Consumer
11 Advocate in Docket No. R-891364. I also testified in Vermont in Docket No.
12 5330 on the cost-effectiveness of the proposed purchased power contract between
13 the Vermont utilities and Hydro-Quebec.

14 Due to my extensive regulatory experience in the public interest, as
15 outlined above, in 1988 I was chosen to serve a 3-year term on the Research
16 Advisory Committee of the National Regulatory Research Institute, an
17 appointment made by the public utility commissioners serving on the NRRI Board
18 of Directors. In addition, within the last 2 years, I have been the project manager
19 on contract research that the Tellus Institute has performed for the U.S.
20 Department of Energy, the U.S. Environmental Protection Agency, the National
21 Association of Regulatory Utility Commissioners (NARUC), the New England
22 Governors' Conference, and the National Council on Competition in the Electric
23 Industry.

1 In the last 2 years, I have spent most of my time analyzing electric utility
2 restructuring issues. I testified before the New Hampshire Public Utilities
3 Commission on issues affecting the design of the state's pilot programs (Docket
4 No. 96-150), and I testified before the New York Public Service Commission on
5 stranded costs, market structures, and other issues related to the ConEd's,
6 NYSEG's, and RG&E's restructuring plans. I also have worked or testified on
7 other restructuring issues in Nevada, New Mexico, New Jersey, Illinois,
8 Pennsylvania, New York, and Michigan. The remainder of my experience is
9 summarized in my resume, which is attached as Exhibit RAR-1.

10

11 Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

12 A. In this case, I am testifying on behalf of the Arizona Residential Utility Consumer
13 Office (RUCO).

14

15 Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS DOCKET?

16 A. No, I have not testified previously in this docket.

17

18 Q. WOULD YOU PLEASE SUMMARIZE THE PURPOSE OF YOUR
19 TESTIMONY IN THIS DOCKET.

20 A. Yes. The purpose of my testimony in this docket is to provide the Arizona
21 Corporation Commission (ACC) with: 1) public policy recommendations on key
22 issues related to the calculation, sharing, and recovery of stranded costs, and 2)
23 presentation of the "retail generation service" methodology for computing

1 stranded costs. To illustrate RUCO's position, I have also done an initial
2 calculation of stranded costs for Arizona Public Service Company (APS), Tucson
3 Electric Power Company (TEP), and the Salt River Project (SRP),
4

5 Q. HAVE YOU TESTIFIED ON STRANDED COST ISSUES BEFORE?

6 A. Yes, I have. On behalf of the Texas Office of Public Utility Counsel (Case No.
7 473-96-2285), I testified before the Texas Public Utilities Commission on public
8 policy recommendations on key issues related to the calculation, sharing, and
9 recovery of stranded costs. On behalf of the American Association of Retired
10 Persons (AARP), I testified before the New York Public Service Commission on
11 key issues related to stranded costs in proceedings for New York State Electric
12 and Gas Corporation (Case No. 96-E-0891), Consolidated Edison Company of
13 New York, Inc. (Case No. 96-E-0897), and Rochester Gas and Electric (Case No.
14 96-E-0898). On behalf of AARP, I also testified before the Public Utilities
15 Commission of New Hampshire on how to structure pricing to implicitly share
16 stranded costs for the purposes of that State's retail access pilot programs (DR 96-
17 150).

18 I have also testified before many public service commissions (in Kansas,
19 Massachusetts, Michigan, Missouri, New Hampshire, New York, Pennsylvania,
20 and Vermont) in many cases regarding the ratemaking treatment of uneconomic
21 costs associated with nuclear and coal plants constructed during the 1970s and
22 early 1980s. In fact, about 15 years ago, Tellus Institute originated the concept of
23 "economic excess capacity," a concept that is basically the same as what has now

1 become known as "stranded costs" or "excess cost over market." Thus, I have
2 testified on many stranded cost-related issues over the last 15 years.

3

4 Q. HAVE YOU TESTIFIED ON ANTI-COMPETITIVE ISSUES BEFORE?

5 A. Yes, I testified on market power issues in the proposed merger of Central Illinois
6 Public Service Company (CIPS) and Union Electric Company (UE) before the
7 Illinois Commerce Commission on behalf of the Illinois Citizens Utility Board
8 (Docket No. 95-0551), and before the Missouri Public Service Commission on
9 behalf of the Missouri Office of the Public Counsel (Docket No. EM-96-149). I
10 also testified before the Maryland Public Service Commission (Docket No. EC96-
11 10-000) and before the Federal Energy Regulatory Commission (Docket No.
12 8725) on behalf of the Maryland Office of People's Counsel regarding the
13 proposed merger between Baltimore Gas & Electric Company (BGE) and
14 Potomac Electric Company (PEPCO). Finally, in New York Case Nos. 96-E-
15 0891, 96-E-0897, and 96-E-0989, I also testified on market power and market
16 structures.

17

18 Q. HOW IS THE REMAINDER OF THIS TESTIMONY ORGANIZED?

19 A. The remainder of this testimony is organized into five major sections:

- 20 2. Summary of Conclusions and Recommendations
- 21 3. Background
- 22 4. Stranded Cost Methodologies
- 23 5. Stranded Cost Results
- 24 6. Stranded Cost Policy

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS.

A. My findings and conclusions on the ACC's Eleven Policy Questions are as follows:

- Stranded Costs should be calculated using the “administrative valuation approach”, which compares projections of the utility’s revenues for electric generation if generation prices were deregulated, and projections of the utility’s revenues for electric generation if generation prices were continued to be regulated based on the utility’s embedded costs of generation. This is equivalent to a market valuation approach if the same projection of market prices is assumed.
- The stranded cost methodology should compute total potentially stranded costs (strandable costs).
- The market price of power should be determined based on the average retail cost of power in the region to serve a particular load based on its load factor and other seasonal characteristics. Developing estimates of the market price of power should include the wholesale price, but should be based on the total retail price for generation services to the customer, which is equal to wholesale price plus a retail margin.
- Stranded costs should include the following categories of costs that are currently being incurred by utilities: generation assets and generation operations and maintenance (O&M) costs, purchase power agreements,

- 1 fuel contracts, generation-related regulatory assets and liabilities, and
2 generation-related administrative and general (A & G) expenses.
- 3 • Stranded costs should be calculated using a time period of at least 15 years,
4 and perhaps as much as 25 years, depending on the expected remaining
5 operational life of the generation resources of a particular utility.
 - 6 • The amount of stranded cost recovery from ratepayers should be calculated
7 administratively and trued-up annually (or at least bi-annually) to account
8 for the actual retail market prices of generation.
 - 9 • The Affected Utilities should bring the embedded cost of generation closer
10 to the market price for generation through appropriate mitigation measures
11 *before* Arizona takes steps towards allowing recovery of stranded costs.
 - 12 • Ratepayers and shareholders should share in paying for stranded costs, if
13 there are any. While the appropriate percentage of this sharing should be
14 determined by the ACC, a 50/50 split is a reasonable approach. Payment
15 by ratepayers should be made through a non-bypassable, nondiscriminatory
16 “wires” charge or competition transition charge (CTC) which would tie the
17 collection of stranded generation costs to the continued use of transmission
18 and/or distribution service.
 - 19 • The time frame for stranded cost recovery should be determined prior to
20 commencing the recovery process. I recommend that the time frame not
21 extend past the end of the transition period defined by the Competition
22 Rules, i.e., January 1, 2003, unless it is determined during 2002 that a large
23 credit is due ratepayers because stranded costs are strongly negative.

1 • While stranded costs are being recovered, there should not be a rate freeze;
2 there should be a rate reduction, with the price of the Standard Offer
3 Service being set based on the market price of retail generation services.
4 However, a price cap on the generation rate is necessary during the
5 transition to completely unregulated generation markets in order to protect
6 ratepayers from any adverse effects of the unregulated generation market
7 during this time period. The rate cap should be at or below the level that
8 rates would have been under continued regulation.

9
10 Q. WHAT CONCLUSION DID YOU REACH AS TO THE LIKELY
11 MAGNITUDE OF THE STRANDABLE GENERATION COSTS THAT APS,
12 SRP, AND TEP HAVE?

13 A. Using the Tellus stranded cost model, I have found that under my Basecase or
14 most likely assumptions APS, SRP, and TEP will have strandable costs over the
15 period 1998-2020 of negative \$838 million, negative \$3.0 billion, and positive
16 \$513 million in 1998 present value dollars, respectively. If the calculation period
17 is reduced to only 15 years (1998-2012), APS, SRP, and TEP will most likely have
18 strandable costs in the range of positive \$102 million, negative \$834 million, and
19 positive \$779 million, respectively, in 1998 present value dollars. Thus, I have
20 concluded that of these three utilities, only TEP may have any significant level of
21 positive strandable costs. This is because the ratepayers have already paid off any
22 uneconomic costs that previously existed on the APS and SRP systems. This
23 implies that unless a negative stranded cost recovery charge is put into place for

1 APS and SRP once retail competition begins, ratepayers may pay more for
2 electricity over the next 15 years and longer, under retail competition than they
3 would pay if regulation were continued. Note that an administratively determined
4 negative stranded cost recovery charge is equivalent to selling the generating units
5 of a particular utility at above net book value, and passing the profit through as a
6 credit to the ratepayers by reducing the existing ratebase. This is what should
7 happen if a sale at above book value were to occur.

8 In this regard, it is also very important to note that my Basecase results
9 indicate that after about 2003, the expected average retail price of power in the
10 unregulated market will exceed the expected regulated price of generation for APS
11 and SRP. This implies that ratepayers will likely pay more under retail competition
12 after 2003 on an annual basis, than if regulation were continued. This forecast
13 graphically illustrates the fact that if a negative stranded cost recovery charge is
14 not put into place for APS and SRP ratepayers for up to 10 years, or if there is no
15 substantial operating or technological-based cost reductions as a result of
16 competition, ratepayers may not benefit from retail competition.

17

18 Q. WHAT ARE YOUR RECOMMENDATIONS TO THE ACC BASED ON
19 YOUR FINDINGS AND CONCLUSIONS SUMMARIZED ABOVE?

20 A. I recommend that the Electric Competition Rules be modified regarding stranded
21 costs. Elaboration of the specific changes recommended are contained at the end
22 of Section 6 of this testimony.

- 1 • Specifically, I recommend the following changes to the Rules: I
2 recommend changing the definition of stranded costs in Section R14-2-
3 1601 (8). I believe changes should also be made to Sections A, B, H, I, J
4 and L of R14-2-1607.
- 5 • I have no recommended changes to Sections C, D, E, F, G, or K of R14-2-
6 1607.

7 In addition, I recommend that the ACC follow-up this generic proceeding with a
8 set of utility-specific proceedings to determine the actual strandable costs of each
9 utility, as the current competition rules provide for. This would allow my initial
10 estimates of stranded costs to be refined. One reason this is necessary is because
11 the ACC has not yet reviewed and ruled on the issue of what the unbundled rates
12 for the Affected Utilities should be. Yet, the proper calculation of stranded costs
13 should include the final ACC ruling on the magnitude of the generation portion of
14 current rates as a starting point. A second reason is that my initial calculations of
15 stranded costs have not had the benefit of information that I would have obtained
16 through discovery that might allow the refinement of certain input assumptions
17 that I used in my calculations of stranded costs.

18
19 Q. BASED ON YOUR INITIAL ESTIMATES OF STRANDED COSTS, WHAT
20 WOULD YOU RECOMMEND TO THE COMMISSION?

21 A. Based on my initial estimates of stranded costs, I recommend to the Commission
22 that the total retail rates of all Affected Utilities be capped during the transition
23 period January 1, 1999 through January 1, 2003, at the very least. This rate cap

1 should ensure that ratepayers would not pay more under retail competition than
2 they would have if regulated generation rates had continued throughout this
3 period. I would also recommend, then, that during 2002, near the end of the
4 transition period, the ACC should check as to whether it still seems likely that
5 retail market prices for the post-2003 period will likely exceed the regulated price
6 of generation. Generally, RUCO supports the concept of retail competition based
7 upon two assumptions; that pressure from the marketplace will result in more
8 efficient generating plant operations and technological innovations that will result
9 in lower costs for consumers. RUCO fully anticipates that technological and
10 operational efficiencies will occur in the open market. Furthermore, the risk of
11 paying for future operational inefficiencies has been eliminated. Additionally,
12 during the transitional period, under RUCO's proposal, residential consumers are
13 protected by a rate cap, a true-up, and the potential amortization of negative
14 stranded cost. However, if it is determined during a true-up process in 2002 that
15 APS' and SRP's stranded costs will be significantly negative, and that the retail
16 market price of power after 2003 will likely exceed the regulated generation price
17 as I currently forecast, the ACC should credit ratepayers for the full amount of
18 these negative stranded costs after 2003 if retail competition is put into effect.

19 In contrast, for TEP the ACC should establish a stranded cost recovery
20 charge based initially on 50 percent of my initial estimate of TEP's strandable
21 costs. *In the utility-specific strandable cost proceeding for TEP*, the ACC should
22 also investigate in Phase II of this docket the reasons for the existence of TEP's
23 strandable costs, and should determine whether a lower percentage than 50 percent

1 of TEP's strandable costs should be charged to ratepayers. If the ACC decides
2 that ratepayers should pay for less than 50 percent of TEP's stranded costs, then
3 the stranded cost recovery charge should be appropriately adjusted. Of course, the
4 ACC should also true-up TEP's stranded cost recovery charge either annually, or
5 at least bi-annually, as actual retail market price data becomes available. Any
6 recovery of stranded costs by TEP should end by January 1, 2003, so that at least
7 there is a possibility that the rates for ratepayers in TEP's service territory will be
8 lower after this date than they would have been under regulation.

3. BACKGROUND

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Q. PLEASE PROVIDE BACKGROUND INFORMATION TO YOUR INVOLVEMENT IN THIS DOCKET.

A. The Arizona Corporation Commission ("ACC" or "Commission") issued Decision No. 59943 on December 26, 1996, approving new rules, A.A.C. R14-2-1601 through R14-2-1616 ("Rules" or "Electric Competition Rules"). The Rules provided for a phased-in transition to retail electric competition in Arizona, beginning on January 1, 1999. These Rules required the creation of special working groups to address several key issues related to the introduction of competitive power markets in Arizona. One group was the Stranded Cost Working Group, comprised of representatives of all stakeholders and coordinated by the Director of Utilities, as required by Rule R14-2-1607.C. The Stranded Cost Working Group contained three subcommittees: the Recovery Mechanism Subcommittee, the Calculation Methodologies Subcommittee, and the Accounting, Finance and Tax Subcommittee. The result of their work was *Docket No. U-0000-94-165: Report to the Arizona Corporation Commission- In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona*. On September 25, 1997, RUCO offered their response to the Stranded Cost Working Group report.

On August 29, 1997, the Commission issued Decision No. 60351 which reopened the Rules and directed the Hearing Division to produce procedural orders to establish hearings regarding aspects of electric utility competition. On

1 October 30, 1997, RUCO filed a Request for Evidentiary and Procedural Order.
2 This procedural order, Docket No. U-0000-94-165, was issued on December 2,
3 1997 to set evidentiary hearings on generic issues related to stranded costs.

4
5 Q. WHAT GENERIC ISSUES RELATED TO STRANDED COSTS DID
6 DOCKET NO. U-0000-94-165 REFER TO?

7 A. The generic issues the docket refers to cover the methodology, computation,
8 mitigation, and recovery of stranded costs. It was ordered this testimony should
9 cover the following issues:

- 10 1) Should the Electric Competition Rules be modified regarding stranded costs?
- 11 2) When should "Affected Utilities" be required to make a stranded cost filing
12 pursuant to A.A.C R14-2-1607?
- 13 3) What costs should be included as part of stranded costs and how should those
14 costs be calculated?
- 15 4) Should there be a limitation on the time frame over which stranded costs are
16 calculated?
- 17 5) Should there be a limitation on the recovery time frame for stranded costs?
- 18 6) How and who should pay for stranded costs and who, if anyone, should be
19 excluded from paying for stranded costs?
- 20 7) Should there be a true-up mechanism and, if so, how would it operate?
- 21 8) Should there be price caps or a rate freeze imposed as part of the development
22 of a stranded cost recovery program and if so, how should it be calculated?
- 23 9) What factors should be considered for mitigation of stranded costs?

1 The First Amended Procedural Order of Docket No. U-0000-94-165 further
2 ordered that Issue No. 3 of the Procedural Order include the following sub-issues:
3 3A) The recommended calculation methodology and assumptions made including
4 any determination of the market clearing price.
5 3B) The implications of the Statement of Financial Accounting Standards No. 71
6 resulting from the recommended stranded cost calculation and recovery
7 methodology.
8 The above issues are specifically addressed in Section 6 in this testimony on
9 Stranded Cost Policy.

10

11 Q. HOW DID RUCO GENERALLY RESPOND TO THE STRANDED COST
12 WORKING GROUP REPORT?

13 A. RUCO responded on September 25, 1997 with comments on procedure, general
14 comments on stranded costs, and on the specific points raised by the stranded cost
15 working group report, and offered responses to Staff's recommendation. Upon
16 examining the Stranded Cost Working Group Report, RUCO decided that a more
17 formal fact-finding process before the Commission was necessary before methods
18 to follow in the electric restructuring process could be determined. RUCO
19 contended that an informed policy-making process necessitated presentation of
20 evidence from all interested parties, with opportunity for cross-examination of
21 witnesses and rebuttal evidence.

22 Q. WHAT WERE RUCO'S GENERAL RESPONSES ON STRANDED COSTS?

1 A. Again, RUCO asserted that an evidentiary hearing was the appropriate forum for
2 addressing the details pertaining to calculation methodology, computation,
3 mitigation, and recovery of stranded costs. RUCO advocated consideration of
4 fairness in the sharing of stranded costs, requesting that customers should not bear
5 the total burden of stranded cost recovery. RUCO argued that utility investors
6 must also assume some responsibility for stranded costs. RUCO also stated the
7 importance of sharing a portion of stranded costs claimed by a utility as a financial
8 incentive to mitigate such costs. Rate unbundling was mentioned by RUCO as the
9 best means to identify the stranded cost component of electric rates. RUCO
10 proposed that unbundling be carried out in a revenue-neutral manner, with each
11 cost component being functionalized, classified and allocated as it is under current
12 rate design.

13
14 Q. PLEASE SUMMARIZE RUCO'S RESPONSE TO THE SPECIFIC POINTS
15 RAISED BY THE STRANDED COST WORKING GROUP REPORT.

16 A. RUCO responded to many specific recommendations addressed in the Report. In
17 summarizing their responses, I will highlight major points of agreement and
18 disagreement. RUCO generally agreed with the definition of stranded costs and the
19 categories of costs included in stranded costs, although they emphasized the
20 importance of taking into account the retailing expenses for generation in
21 determining the retail price of generation services. RUCO agreed with the Staff
22 report that the Rules should be changed to allow stranded cost recovery from
23 customers who are on standard offer service, that stranded costs should be

1 recovered from ratepayers using a charge with both an energy and demand
2 component, and that tariffs for each rate class should continue to have the same
3 billing determinants as they do now. RUCO also disagreed with the use of exit
4 fees, clarified their position that a rate cap should be considered during the
5 transition period only, not during the competitive period, and clarified that a
6 revenue-neutral unbundling approach should be used, where rate design remains
7 constant and is not updated to correct perceived flaws in the current rate design.

8

9 Q. DID RUCO RESPOND TO STAFF'S RECOMMENDATIONS?

10 A. RUCO responded on a point-by-point basis. Many of their responses have been
11 incorporated into and restated in this testimony because I agree with those
12 responses. Please refer to Section 6 on Stranded Cost Policy for details.

4. STRANDED COST METHODOLOGIES

A. Administrative Versus Market Valuation

Q. WHAT METHODOLOGIES ARE AVAILABLE TO ESTIMATE STRANDED GENERATION COSTS?

A. There are generally two methodologies for calculating stranded generation costs: *the market valuation approach* and *the administrative valuation approach*. The market valuation approach is when a utility's stranded costs are based on the differences between the *actual* auction, sale, or spin-off price of each of the utility's generation assets and the actual embedded cost of each of the utility's generation assets, net of generation-related Administrative and General (A&G) expenses. Under the administrative valuation approach, a utility's stranded generation costs would be based on the difference between *projections* of the utility's revenues for electric generation if generation prices were deregulated, and *projections* of the utility's revenues for electric generation if generation prices continued to be regulated based on the utility's current embedded costs of generation. RUCO supports the administrative valuation approach for calculating stranded generation costs.

Q. WHAT ROLE DOES UNBUNDLING PLAY IN EACH OF THE METHODOLOGIES DISCUSSED ABOVE?

A. Both of the methodologies discussed above require knowing the utility's total (i.e., economic and uneconomic) embedded cost of generation. This necessitates

1 correctly *unbundling* the utility's embedded-costs-of-service from the utility's
2 Cost-of-Service Study used to develop existing rates in its last base rate case.
3 Electric service costs should first be unbundled into: 1) total generation and
4 generation-related (i.e., competitive) ancillary services, 2) transmission and
5 transmission-related (i.e., non-competitive) ancillary services, 3) distribution
6 (including existing DSM), and 4) customer services.¹ Then, by using one of the
7 methodologies discussed above, the *economic* generation and generation-related
8 ancillary service costs would be separated from the *uneconomic* (i.e., stranded)
9 generation and generation-related ancillary service costs.

10

11 Q. WITH RESPECT TO TEP, APS, AND SRP, WHAT NEEDS TO BE DONE IN
12 ORDER TO ACCURATELY UNBUNDLE THE UTILITY'S COSTS OF
13 PROVIDING EACH DISTINCT ELECTRIC SERVICE?

14 A. Rule 14-2-1606(C) ordered utilities, with the exception of SRP, file unbundled
15 tariffs on December 31, 1997. These tariffs need to be evaluated. Utilities could
16 have unbundled their current rates based on the Cost-of-Service Studies used in
17 each utility's last base rate case. In this way, the rates for those services which are
18 to remain regulated (i.e., transmission and distribution) will be fair and will not be
19 recovering any costs that are attributable to services that may become unregulated
20 (i.e., generation and aggregation). If APS, TEP and SRP developed new Cost-of-

¹ It will not be obvious how all of the costs, for example administrative and general ("A&G") costs, should be categorized. However, costs that pose this challenge should not merely be allocated to the transmission and distribution (i.e., regulated) categories because this might allow the utility's shareholders to avoid paying their share of some potentially stranded generation costs.

1 Service Studies and use these studies to unbundle their respective rates, then the
2 issues of rate unbundling could be obscured by issues of rate redesign. This
3 second approach would not produce an unbundling of current rates.

4
5 Q. PLEASE DESCRIBE THE MARKET VALUATION APPROACH IN MORE
6 DETAIL.

7 A. In a perfect market, the sale price (which defines the market value) of each
8 generation asset would reflect each buyer's estimates of the future costs and
9 benefits of running the plant. Specifically, as described by Jonathan Lesser and
10 Malcolm Ainspan:

11 "the sale price [would] equal the buyer's expectation of the
12 discounted² ... present value of the anticipated revenue stream less
13 the present value of the future operating costs, plus the salvage
14 value, if any."³

15 If an asset's market value is below its depreciated book value plus the
16 present value of generation-related A&G expenses, then this difference is a
17 stranded cost. If an asset's market value is above its depreciated book value plus

² The market price of a generation asset would tend to reflect a private discount rate (the rate at which the value of money changes over time). Relative to regulated utility discount rates, private discount rates are higher. Higher discount rates would mean that the "value" of a generation asset to private investors in the market would be lower than the "value" of the asset to a utility and its ratepayers under regulation. Therefore, the switch away from regulation and its use of a regulated utility discount rate to a competitive market and its use of a private discount rate in itself creates some stranded generation costs.

³ Lesser and Ainspan. "Using Markets to Value Stranded Costs." *The Electricity Journal*, October 1996; page 69.

1 A&G, then this difference is a negative stranded cost, which should be used to off-
2 set the positive stranded costs associated with other assets.

3

4 Q. WHAT ARE THE ADVANTAGES OF THE MARKET VALUATION
5 APPROACH?

6 A. The advantages of the market valuation approach are that: 1) the calculation of
7 stranded costs would be relatively straightforward, 2) the calculation of stranded
8 costs would be final, and 3) the divestiture of generation assets required by the
9 approach might mitigate the potential exercise of vertical and horizontal market
10 power in a deregulated generation market.

11

12 Q. WHAT ARE THE DISADVANTAGES OF THE MARKET VALUATION
13 APPROACH?

14 A. The disadvantages of the market valuation approach are that: 1) the stranded
15 costs would likely be significantly mis-estimated if the competitive generation asset
16 market is undeveloped, 2) the divestiture of generation assets required by the
17 approach might increase the potential exercise of horizontal market power in a
18 deregulated generation market, 3) the approach can not easily accommodate a
19 true-up mechanism to protect ratepayers from paying too much in stranded costs
20 and utilities from recovering too little in stranded costs, 4) the stranded costs could
21 be affected by the amount of the utility's assets (or a neighboring utility's assets)
22 that are to be sold over a given period, as well as the timing of each sale, and 5)
23 setting up the appropriate procedures for auctioning or spinning-off the generation

1 assets would not be straightforward, nor would sorting out the federal and state
2 tax implications.

3

4 Q. PLEASE DESCRIBE THE ADMINISTRATIVE VALUATION APPROACH IN
5 MORE DETAIL.

6 A. Under the administrative valuation approach, stranded costs would be calculated
7 as the net present value of the change in generation-specific revenues that a utility
8 would experience over some specified time period as a result of selling electricity
9 at market prices rather than at regulated prices. A utility's generation-specific
10 revenue requirements would include the fixed and variable costs of generation, and
11 some A&G expenses.

12 The administrative valuation approach could be used to calculate a utility's
13 stranded costs regardless of whether or not divestiture of the utility's generation
14 assets occurs on a voluntarily basis. In other words, a commission may believe
15 that there are advantages to allowing a utility to divest its generation assets, but
16 may also believe that until a competitive generation asset market develops, the
17 asset sale prices should not be relied upon for the purposes of calculating stranded
18 costs. Because asset sale prices could fluctuate significantly during the years when
19 competition is developing, regulators may prefer to base the initial estimate of a
20 utility's stranded costs on their *own* projections of market prices for generation.
21 Furthermore, regulators could adjust (or "*true-up*") their initial stranded cost
22 estimate annually to reflect actual market prices as they become known.

1 Q. WHAT ARE THE ADVANTAGES OF THE ADMINISTRATIVE
2 VALUATION APPROACH?

3 A. The advantages of the administrative valuation approach are as follows: 1) The
4 administrative evaluation approach could accommodate a true-up mechanism that
5 would ensure ratepayers and utilities pay and recover their fair share of stranded
6 costs, and would alleviate the need for exact projections of market prices for
7 generation. 2) This approach would explicitly calculate stranded costs over a
8 significant length of time (determined by the state regulatory commission). 3) This
9 approach would allow a utility to divest some or all of its generation assets, but it
10 would hold ratepayers harmless vis-à-vis the sale prices of any assets. 4) This
11 approach would allow for distinguishing between the stranded costs themselves
12 and the financing costs associated with them (i.e., the return on stranded
13 investments) for the purpose of proposing a sharing mechanism.

14
15 Q. WHAT ARE THE DISADVANTAGES OF THE ADMINISTRATIVE
16 VALUATION APPROACH WITH A TRUE-UP MECHANISM?

17 A. The disadvantages of the administrative valuation approach with a true-up
18 mechanism are that: 1) the initial calculation and the annual true-ups of stranded
19 costs would not be as easy and straightforward as the calculations under the
20 market valuation approach, and 2) the true-up mechanism would still not entirely
21 protect ratepayers from the negative price effects of an undeveloped competitive
22 generation market and/or market power.

1 **B. Description of Tellus Strandable Cost Model**

2 Q. WHAT MODEL DID YOU USE TO CONDUCT YOUR ANALYSIS OF THE
3 TEP, APS AND SRP STRANDED COSTS?

4 A. I used the Tellus Strandable Cost Model (SCM), which is based on the
5 administrative valuation approach to valuing potentially stranded or uneconomic
6 costs.

7
8 Q. PLEASE EXPLAIN BRIEFLY THE METHODOLOGY EMPLOYED IN THE
9 STRANDABLE COST MODEL THAT YOU USED TO DEVELOP THE
10 ESTIMATES.

11 A. The Tellus SCM is a simple spreadsheet model which performs three independent
12 analyses: an unbundling analysis, a market price analysis for retail generation
13 services, and projections of potentially strandable costs over a specified period of
14 time. Using utility-specific data from the most recent FERC Form 1⁴, the model
15 develops an estimate of a utility's unbundled costs of generation, transmission,
16 distribution and customer costs that are reflected in the utility's average retail rate.
17 The unbundled cost of generation, or retail generation services, is then compared
18 to a market price for retail generation services (RGS) in order to estimate potential
19 stranded costs. In these analyses, I used 1996 as a base year, since APS' and
20 TEP's most recently available FERC Form 1s were from December 31, 1996. I
21 used 1996 financial data for SRP, as well. However, note that I have expressed all

⁴ The FERC Form 1 is a mandatory filing regulated utility's must make to the Federal Energy Regulatory Commission under Federal Power Act, Sections 3, 4(a), 304 and 309 and 18 CFR 141.1.

1 my stranded cost results in 1998 present value dollars, not in 1996 present value
2 dollars.

3 Q. DO YOU HAVE A DESCRIPTION OF THE TELLUS SCM?

4 A. Yes. A description of the Tellus SCM is provided in Exhibit (RAR-12).

5

6 Q. PLEASE DESCRIBE HOW YOU UNBUNDLED TEP'S , APS' AND SRP'S
7 REVENUES.

8 A. I entered utility-specific costs and revenues using information provided in each
9 utility's FERC Form 1 for 1996, or for SRP, a comparable source. The unbundled
10 revenues were allocated to generation, transmission, distribution, and customer
11 related expenses, based on a few simple allocation methods. Please see Exhibits
12 (RAR-4) Table 2 (p. 3) for APS' rate unbundling results, (RAR-6) Table 2 (p. 3)
13 for SRP's rate unbundling results, and , (RAR-8) Table 2 (p.3) for TEP's rate
14 unbundling results.

15

16 Q. HOW WERE PLANT-RELATED COSTS ALLOCATED TO THE
17 GENERATION, TRANSMISSION, DISTRIBUTION, AND CUSTOMER
18 COST COMPONENTS?

19 A. Ratebase or plant-related costs like depreciation and interest were allocated to
20 each cost component based on that component's fractional contribution to net
21 plant, e.g. generation-related net plant divided by total net plant was used to
22 allocate these costs to the generation cost component.

23

1 Q. HOW ARE ADMINISTRATIVE AND GENERAL COSTS ALLOCATED TO
2 THE GENERATION, TRANSMISSION, DISTRIBUTION, AND CUSTOMER
3 COST COMPONENTS?

4 A. Administrative and General costs are allocated to each functional cost component
5 based on each component's fractional contribution to O&M less the sums of fuel
6 and A&G expenses.

7

8 Q. ONCE THE TOTAL OPERATING REVENUES HAVE BEEN CALCULATED,
9 ARE THERE ANY ADDITIONAL ADJUSTMENTS MADE PRIOR TO
10 CALCULATING A PER KWH UNIT COST FOR EACH COST
11 COMPONENT?

12 A. Yes. Wholesale Revenues are subtracted from Operating Revenues to calculate
13 the Total Retail Revenues. It is the Total Retail Revenues for each cost
14 component which are divided by Total Retail Sales to arrive at the unbundled per
15 kWh cost for each cost component.

1 **C. The Market Price of Retail Generation Services**

2 **Q. WOULD YOU BRIEFLY REVIEW THE CONCEPT OF "UNBUNDLING" AS**
3 **IT RELATES TO THE CALCULATION OF STRANDED COSTS?**

4 A. Again, unbundling refers to the process each utility must complete of dividing its
5 current single or bundled rate into separate rates for customer services,
6 transmission, distribution, and retail generation services. During this unbundling
7 process, administrative and general costs (A&G) and various other common costs
8 must be allocated fairly between these services. The resulting rates for
9 transmission, distribution, and customer services would continue to be regulated
10 by the ACC as monopoly services. However, the prices for retail generation
11 services in Arizona will be competitive and set by the market beginning January 1,
12 1999. Thus, the difference between each utility's cost-based rate for retail
13 generation services and the market price of retail generation is each utility's
14 respective stranded cost for generation.

15

16 **Q. WHAT TYPES OF COSTS WILL A COMPETITIVE SUPPLIER OF RETAIL**
17 **GENERATION SERVICES LIKELY INCUR?**

18 A. In addition to the cost of buying power at wholesale, the types of costs that a
19 competitive supplier will incur to provide retail generation services fall into the
20 following categories:

21 1. Generation-related customer services (e.g., billing, bill collection,
22 responding to customer inquiries and complaints, arranging for
23 new services or for switching services, etc.);

- 1 2. Ancillary services, such as load balancing and forecasting activities at the
- 2 distribution circuit level needed to settle accounts with wholesale providers
- 3 and to determine T&D charges and requirements, and risk management;
- 4 3. Marketing and advertising, including marketing incentives for new
- 5 customers;
- 6 4. Generation-related administrative and general services, such as contracting
- 7 for power, managing the aggregation company, providing office space to
- 8 employees, etc.;
- 9 5. Profits and income taxes on profits; and
- 10 6. Other taxes.

11

12 Q. SHOULD EACH TYPE OF COST LISTED ABOVE BE INCLUDED IN THE

13 MARKET PRICE FOR RETAIL GENERATION SERVICES USED TO

14 COMPUTE STRANDED COSTS?

15 A. Yes, each type of cost listed above should be reflected in the estimated market

16 price for retail generation services used to compute stranded costs. Each type of

17 cost will be incurred by retail generation suppliers, regardless of whether they

18 provide each and every service from in-house resources or whether they contract

19 out certain services. Thus, projections of these retailing costs, which make up

20 what I call the "retail margin," should be added to projections of competitive

21 wholesale prices in order to derive a more accurate market price for retail

22 generation services (an "RGS" market price) for computing stranded costs. Thus,

23 it is the total market price for retail generation services as determined by

1 alternative suppliers to the utilities that will determine the income that the existing
2 utilities will be able to earn in the retail market.

3

4 Q. DID YOU EVALUATE THE LIKELY RETAIL MARGIN FOR APS, TEP AND
5 SRP?

6 A. Yes, I did. The retail margin developed for each utility is a combination of A&G-
7 related generation expenses developed in the unbundling process for each utility,
8 and an estimate of the additional retail costs which would be incurred in order to
9 sell generation services to customers within the State of Arizona.

10

11 Q. WHAT DID YOU ESTIMATE THE RETAIL MARGIN FOR APS, SRP, and
12 TEP TO BE?

13 A. I estimated that a lower bound for the total retail margin would be about 0.77
14 cents per kWh in 1996 dollars. This is the sum of .50 cents per kWh for A&G
15 related expenses, and a lower-bound estimate of additional retail services expenses
16 of 0.27 cents per kWh. I have assumed that the retail margin would be the same
17 for customers of all utilities within Arizona, since I have assumed the existence of a
18 single state-wide retail market for generation.

19

20 Q. WHAT DOES THE CONCEPT OF RETAIL GENERATION SERVICES
21 IMPLY FOR STRANDABLE COST CALCULATIONS?

22 A. The discussion above implies that the market price used to calculate costs that
23 might become stranded due to retail competition must be the market price for retail

1 generation services. Many parties have used wholesale market prices to calculate a
2 utility's strandable costs, but by doing so, they have significantly over-estimated
3 strandable costs.

4 In estimating ranges of the Affiliated Utilities' strandable costs, I have
5 included the low retail adders appropriate for both small and large customers that I
6 computed, and have weighted them across the 1996 sales of the small and large
7 customer classes for the sum of APS' and TEP's retail sales in order to derive a
8 low and a high value of the retail margin for the total load. Below, I will describe
9 the full range of retailing costs that an efficient competitive supplier of retail
10 generation services might incur in serving small and large customers. I will also
11 provide estimates of the magnitude of each component of retail generation service
12 cost. These estimates are summarized in Exhibit___(RAR-3), under the heading
13 "Cost Components of a Retail Generation Services Adder."

14
15 Q. HAVE OTHER STATES ENDORSED THE CONCEPT OF MARKET PRICES
16 OF RETAIL GENERATION SERVICES?

17 A. Yes, the New York State Public Service Commission, the New Hampshire Public
18 Utilities Commission, and the Pennsylvania Public Utilities Commission have
19 endorsed the concept of market prices of retail generation services for the purpose
20 of establishing generation credits for pilot program participants.

21 In New York Case No. 96-E-0898, Rochester Gas and Electric identified
22 thirteen "retailing functions" that would be the primary responsibility of the
23 distribution company and fourteen retailing functions that would be the primary

1 responsibility of the competitive supplier under retail competition. (See
2 Exhibit __ (RAR-11) for the list of retailing functions.) Furthermore, in New York
3 Case No. 96-E-0948, the Commission established fixed adders to capture potential
4 retailing generation costs and to encourage farms and food processors to
5 participate in one of the state's retail pilot programs. The Commission set the
6 retail adder at \$4 per MWH for food processor participants (larger customers) and
7 \$10 per MWH for farm participants (smaller customers).⁵

8 In the New Hampshire pilot programs, the Public Utilities Commission
9 approved a marketing cost credit of \$3.70 per MWH for the state's 2-year pilot
10 program for small customers. Finally, in Pennsylvania, the Commission concluded
11 that for residential and commercial customers participating in the state's pilot
12 programs, a retail generation credit of 3.0 cents per kWh should be adopted, along
13 with a Customer Participation Credit ("CPC") of 13 percent of the difference
14 between the current retail rate and the generation credit.⁶

15
16 Q. PLEASE BEGIN BY DISCUSSING EACH COST COMPONENT OF THE
17 RETAIL MARGIN, IN PARTICULAR GENERATION-RELATED
18 CUSTOMER SERVICE COSTS IN ORDER TO ILLUSTRATE HOW YOU
19 DERIVED YOUR RESULTS IN EXHIBIT __ (RAR-3).

⁵ The difference is explained by the New York Public Service Commission as follows: Actual retail access experience may show that avoidable retail and other expenses are greater for smaller customers on a unit (per kWh) basis, and it also appears that more of a per unit (kWh) discount will be necessary to encourage the participation of such smaller customers in the programs." (Case 96-E-0948 - Order Establishing Retail Access Pilot Programs, page 7).

⁶ Docket Nos. P-00971168, P-00971169, P-00971170, P-00971171, P-00971172, P-00971173, P-00971175, and P-00971183. Motion of Chairman John M. Quain at 3 (August 21, 1997).

1 A. A key generation-related customer service cost is the cost of billing customers for
2 retail generation services and collecting bill payments. Under retail generation
3 services, there will also be customer calls to handle, including requests for
4 information, requests for service, and complaints. Thus, generation-related
5 customer service costs will at least include: 1) billing and collection service costs,
6 and 2) costs to have customer service representatives available to answer
7 telephone inquiries and requests from customers. Competitive alternative suppliers
8 may do their own billing, they may pay the distribution company to do their billing
9 for them, or they may pay a third party to do their billing. If they do their own
10 billing, they will need to invest in computer systems to perform the task. If they
11 pay the distribution company to do their billing, they should pay whatever the
12 incremental cost is to the utility to perform this task. If they contract with a
13 private billing company, they will pay according to their contract with that
14 company.

15
16 Q. WHAT IS YOUR ESTIMATED RANGE FOR GENERATION-RELATED
17 CUSTOMER SERVICE COSTS?

18 A. My estimates of generation-related customer service costs range from a low of
19 \$1.00 per month per customer to a high of \$2.00 per month per customer, or
20 about \$1.10 per MWH to \$2.20 per MWH, for small customers such as those
21 served by APS and TEP, who together use an average of 917 kWh per month. My
22 estimate of generation-related customer service costs is about \$0.50 per MWH for
23 large customers in the low case and about \$1.00 per MWH in the high case.

1 My estimates are based, in part, on claims made by utilities in other states.
2 As part of its pilot proposal, Pennsylvania Power & Light (PP&L) proposed a fee
3 of \$1.50 per bill for Billing and Collection Service, even though it claimed that its
4 true cost would be \$2.05.⁷ Similarly, PECO Energy Company proposed a fee of
5 \$0.90 per bill.⁸ It is important to note that so far, there is no evidence that the
6 utilities' proposed fees reflect the true *incremental* costs that they would incur.
7 Nonetheless, these proposed fees provide a conservative range of prices for *all*
8 generation-related customer services, since my proposed ranges do not include any
9 costs that a supplier would incur to install a billing and collection system or to
10 answer customers' telephone inquiries and requests, outside of billing-related calls.

11

12 Q. PLEASE DISCUSS THE COSTS OF ANCILLARY GENERATION-RELATED
13 SERVICES OTHER THAN THOSE THAT WILL BE PROVIDED UNDER
14 TRANSMISSION TARIFFS REQUIRED BY FERC ORDER NO. 888.

15 A. There are likely to be additional generation-related ancillary services that were not
16 identified in FERC Order No. 888. As I mentioned earlier, in New York Case No.
17 96-E-0898, Rochester Gas and Electric has identified twenty seven "retailing
18 functions" that would be the responsibility of the distribution company and/or the
19 competitive supplier. (Refer to Exhibit ___(RAR-11) for the list of other potential
20 ancillary services.) Of these twenty seven functions, ones such as "forecasting of
21 customer energy requirements" and "scheduling of capacity and energy purchases

⁷ Docket No. P-00971183, PP&L's Comments at 40 (May 22, 1997).

⁸ Docket No. P-00971170, PECO's initial petition.

1 and delivery to the service area" could all be classified as additional generation-
2 related ancillary services. These services will be either partially or fully the
3 responsibility of alternative suppliers, depending on the responsibilities of the
4 Independent System Operator (ISO).
5

6 Q. WHAT IS YOUR ESTIMATED RANGE FOR THE COSTS OF ANCILLARY
7 SERVICES OTHER THAN THOSE THAT WILL BE PROVIDED UNDER
8 TRANSMISSION TARIFFS REQUIRED BY FERC ORDER NO. 888?

9 A. In order to be conservative, my estimate of ancillary services other than those
10 identified in FERC Order No. 888 ranges from \$0 per MWH to \$1.00 per MWH
11 for both small and large customers under the low and high cases.
12

13 Q. PLEASE DISCUSS GENERATION-RELATED A&G COSTS.

14 A. All vertically-integrated utilities have incurred, and competitive alternative
15 suppliers will continue to incur, generation-related A&G costs. These costs
16 include those for corporate headquarters, salaries for top management, office
17 supplies and services, administrative support, etc. Thus, when utilities properly
18 unbundle their rates, they should allocate generation-related A&G to the
19 generation component of rates. Furthermore, economic generation-related A&G
20 should be moved to the utilities' own unregulated aggregation affiliates, if such
21 affiliates are established as the sale of retail generation services become
22 deregulated. This important aspect of unbundling has already been supported by
23 some Pennsylvania utilities. For example, in the Code of Conduct proposed by

1 Pennsylvania Electric Company and Metropolitan Edison Company, the companies
2 stated that "the LDC shall fairly allocate to its Affiliate costs for general
3 administration or support services, ... so as not to give the LDC or its Affiliate an
4 unfair advantage over competitors through an allocation of these costs."⁹ This
5 policy of fairly allocating generation-related A&G costs as the sales of retail
6 generation services shift from the regulated utility to the unregulated subsidiary of
7 the utility should be followed by all utilities, regardless of whether they only
8 functionally unbundle, or whether they fully divest their generation function.

9
10 Q. WHAT IS YOUR ESTIMATE OF GENERATION-RELATED A&G COSTS
11 FOR ALTERNATIVE SUPPLIERS?

12 A. My estimate of generation-related A&G costs is \$5.00 per MWH for small and
13 large customers in both low and high cases. This figure is based on APS' relatively
14 low generation-related A&G costs, which I arrived at by allocating 71 percent of
15 the utility's total A&G costs in 1996 to its generation function. The generation-
16 related A&G value for SRP is almost identical. This figure is about 94 percent of
17 my estimate of the 1994 national average generation-related A&G cost for
18 investor-owned utilities (not corrected for inflation).¹⁰ Therefore, I have made the
19 assumption that efficient alternative suppliers could provide generation-related
20 A&G at about the same cost as APS and SRP, since alternative suppliers will likely

⁹ Companies' respective initial pilot proposal filings at 31.

¹⁰ The 1994 national average generation-related A&G component is approximately \$5.30 per MWH and the national average bundled retail rate is \$71.60 per MWH for investor-owned utilities.

1 try to keep their generation-related A&G costs to a minimum and APS and SRP
2 appears to be fairly efficient as far as their generation-related A&G costs are
3 concerned.

4
5 Q. PLEASE DISCUSS MARKETING AND ADVERTISING COSTS.

6 A. Competitive alternative suppliers will incur significant costs for marketing and
7 advertising, which are costs that regulated vertically integrated utilities have not
8 had to incur because their customers have been captive. (Sometimes the utilities
9 have incurred these costs on a voluntary basis.) Alternative suppliers will have to
10 incur large marketing costs initially to gain market share. They will have to make
11 significant investments in marketing and advertising to foster good customer
12 relations and to try to convince retail customers (especially smaller consumers) to
13 switch from the existing service provider they know (and to which they may be
14 loyal) to one they do not know.

15 Q. WHAT IS YOUR ESTIMATE OF MARKETING AND ADVERTISING
16 COSTS?

17 A. My estimate of marketing and advertising costs ranges from a low of \$1.00 per
18 MWH to a high of \$2.00 per MWH for small customers, and a low of \$0.50 per
19 MWH to a high of \$1.00 per MWH for large customers. My estimated range
20 derives, in part, from the New Hampshire pilot programs. There, the Public
21 Utilities Commission approved a marketing cost credit of \$3.70 per MWH for the
22 state's 2-year pilot programs for small customers. The N.H. PUC arrived at this
23 estimate by assuming that a competitive supplier participating in a 24 month pilot

1 program would spend \$44 on a customer who consumes an average of 500 kWh
2 per month. Many alternative suppliers in the N.H. pilots offered to give each
3 residential pilot participant approximately \$25 as a "signing bonus" or roughly the
4 equivalent in conservation measures and gifts. It is reasonable to assume that these
5 suppliers will spend an additional \$19 or more per customer over 2 years on other
6 forms of marketing and advertising, such as telemarketing, multi-media
7 advertising, and the like.

8 If suppliers in Arizona spend \$44 in marketing and advertising over a 2-
9 year period on small customers who consume an average of 917 kWh per month,
10 then that it is equivalent to spending about \$2.20 per MWH for small customers.
11 Even if suppliers spend as little as \$24 per customer on marketing and advertising,
12 this is equivalent to spending about \$1.10 per MWH on a customer who consumes
13 917,000 kWh per month for 24 months. I am assuming that the average customer
14 may switch suppliers or need to be offered an incentive to stay with his/her existing
15 supplier every 2 years or so. On a per MWH basis, marketers are likely to spend
16 even less than this on large customers. This is why I chose the conservative range
17 of \$0.50 per MWH to \$1.00 per MWH for large customers.

18
19 Q. ARE THERE ANY OTHER COST COMPONENTS THAT ALTERNATIVE
20 SUPPLIERS WILL HAVE TO COLLECT FROM RETAIL RATEPAYERS IN
21 THE LONG RUN?

22 A. Yes. If alternative suppliers want to stay in business during the mid- to long-term
23 under retail competition, they will need to earn a profit margin on more than just

1 their capital investment in generation, if they have any such investments. (Some
2 alternative suppliers may purchase all their power from others.) Once they earn
3 this profit margin, they will need to pay federal and state income taxes on it.
4 Therefore, in the longer run, alternative suppliers will need to recover these types
5 of costs through the prices they charge for retail generation services.

6 I have assumed a profit margin of 10 percent on the four above-mentioned
7 components of the retail adder, and an income tax rate of 35 percent of the profit
8 margin.

9
10 Q. PLEASE SUMMARIZE WHAT YOUR PROPOSED LOW AND HIGH
11 RETAIL ADDERS ARE FOR SMALL AND LARGE CUSTOMERS.

12 A. Once the costs of the above components are added together, my proposed retail
13 adder for small customers ranges from a low of \$8.20 per MWH to a high of
14 \$11.80 per MWH. My proposed retail adder for large customers ranges from a
15 low of \$6.40 per MWH to a high of \$8.50 per MWH. I then took a weighted
16 average of the low and high estimates based the sum of APS' and TEP's 1996
17 retail sales by customer class that were cited in their 1996 FERC Form #1 data.
18 Thus, my estimated retail adder, averaged across small and large customer classes,
19 ranges from a low of 0.77 cents per kWh to a high of 1.1 cents per kWh. For my
20 analysis of stranded costs I only utilized the low case value of 0.77 cents per kWh.

1 **D. Unbundling Results for APS, SRP and TEP**

2 Q. DID YOU USE THE TELLUS UNBUNDLIGN METHODOLOGY TO
3 DEVELOP ESTIMATES OF THE UNBUNDLED REVENUES FOR APS, TEP,
4 AND SRP?

5 A. Yes, I did.

6

7 Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION,
8 DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR APS?

9 A. The unit unbundled revenues for APS were as follows:

- 10 • Generation - 5.02 cents per kWh
11 • Transmission - 0.59 cents per kWh
12 • Distribution - 2.06 cents per kWh
13 • Customer - 0.38 cents per kWh.

14 The total average retail rate was 8.05 cents per kWh.

15 Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION,
16 DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR TEP?

17 A. The unit unbundled revenues for TEP were as follows:

- 18 • Generation - 6.12 cents per kWh
19 • Transmission - 0.83 cents per kWh
20 • Distribution - 1.32 cents per kWh
21 • Customer - 0.29 cents per kWh.

22 The total average retail rate was 8.55 cents per kWh.

23

1 Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION,
2 DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR SRP?

3 A. The unit unbundled revenues for SRP were as follows:

- 4 • Generation - 4.85 cents per kWh
- 5 • Transmission - 0.38 cents per kWh
- 6 • Distribution - 1.02 cents per kWh
- 7 • Customer - 0.27 cents per kWh.

8 The total average retail rate was 6.52 cents per kWh.

9

10 E. **The Wholesale Market Price Projection**

11 Q. PLEASE DESCRIBE THE METHODOLOGY YOU USED TO PROJECT
12 WHOLESALE ELECTRICITY PRICE.

13 A. The major assumption underlying my methodology is that the future average
14 annual wholesale market price of electricity could be approximated by the average
15 unit cost of supplying energy and capacity to meet utility's incremental load in
16 each year using only state-of-the-art new Combustion Turbine (CT) and Combined
17 Cycle (CC) power plants. These two types of power plants were chosen because
18 they are well-known to be the lowest cost new technologies to meet peaking and
19 baseload type demand, respectively.

20

21 Q. PLEASE EXPLAIN WHY THIS PROJECTED AVERAGE UNIT COST FOR
22 MEETING INCREMENTAL LOADS YIELDS A REASONABLE ESTIMATE
23 OF THE AVERAGE ANNUAL WHOLESALE PRICE OF ELECTRICITY.

1 A. First of all, it is important to point out that this methodology does **not** intend to
2 provide a precise prediction of the wholesale market price of electricity that may
3 evolve in a deregulated power market. Instead, it attempts to estimate a **lower**
4 bound for such prices.

5 The exact market price of electricity will depend on the actual structure of
6 electricity market that is yet to evolve in Arizona. However, regardless of such a
7 structure, at some point in the future the existing generation capacity will become
8 insufficient to meet growing demand and new generation capacity must be built.
9 In a competitive deregulated environment, a new market entry will occur only if
10 the market price of electricity is high enough to compensate project developers for
11 costs incurred to finance, construct, and operate new power plants. Thus, the
12 wholesale market price for power to meet a certain type of load (e.g., peaking,
13 cycling, baseload) should be no less than the unit cost of financing, constructing,
14 and operating those plants needed to meet that load in the least-cost way.

15
16 Q. HOW DID YOU ESTIMATE THE UNIT COST OF FINANCING,
17 CONSTRUCTING, AND OPERATING INCREMENTAL GENERATION
18 CAPACITY REQUIRED TO MEET INCREMENTAL LOAD FOR EACH
19 UTILITY FOR WHICH YOU COMPUTED STRANDABLE COST?

20 A. I considered the two generation technologies -- state-of-the-art new gas fired
21 Combustion Turbines (CT) and Combined Cycle (CC) power plants and calculated
22 the least cost mix of these technologies required to meet the 1996 load profile of
23 each utility.

1 Q. WHY DID YOU CALCULATE THE MIX REQUIRED TO MEET THE
2 ENTIRE SYSTEM LOAD AS OPPOSED TO CALCULATING THE MIX
3 REQUIRED TO MEET AN INCREMENTAL LOAD?

4 A. It is important to note that the unit cost of power does not depend on the
5 magnitude of the incremental load, but on its shape. If the shape of utility's
6 incremental load is the same as the shape of its total system load in 1996, the
7 resulting unit cost of generation found for the system load would be the same as
8 for the incremental load. In other words, calculating a unit cost of serving an
9 entire system load is just a method of computing a unit cost of serving an
10 incremental load that has the same load characteristics.

11

12 Q. WHAT WERE YOUR INPUT ASSUMPTIONS REGARDING THE COST
13 AND HEAT RATES OF CT AND CC POWER PLANTS?

14 A. I used the most recent available information regarding the cost and heat rates of
15 CC and CT plants. The CC data I used was as follows: capital cost of \$383 per
16 kW, fixed O&M cost of \$11.7 per kW-year, variable O&M cost of 0.2 mills per
17 kWh, and heat rate of 6,500 Btu per kWh. I used CT data developed by Tellus
18 Institute for use in *Energy Innovations - A Prosperous Path to a Clean*
19 *Environment* (June 1997). The CT data were as follows: capital cost of \$275 per
20 kW, fixed O&M cost of \$9.4 per kW year, variable O&M cost of 0.1 mills per kW,
21 and heat rate of 11,900 Btu per kWh.

22

1 Q. WHAT FIXED CHARGE FACTOR DID YOU USE TO ACCOUNT FOR
2 CAPACITY COSTS ON AN PER KWH BASIS?

3 A. I used a real levelized fixed charge factor of 10.88 percent. This fixed charge
4 factor assumes a 20-year financing period at a private rate of 10.5 percent which is
5 intended to be for projects developed without regulatory guarantee for cost
6 recovery.

7
8 Q. HOW DID YOU ESTIMATE THE AVERAGE "BUS BAR" COST OF THE
9 OPTIMAL CC/CT MIX?

10 A. To determine the likely future mix of CCs and CTs for a utility's system, the
11 methodology I used conducts a "crossover calculation" to determine the capacity
12 factor below which CTs will operate at least-cost and above which CCs will
13 operate at least cost. The outcome of the crossover calculation is a key input to
14 determine the combination of CCs and CTs which would serve this utility's system
15 at the lowest cost, based on the load profile of the utility in the base year.

16
17 Q. WHAT ASSUMPTION DID YOU MAKE REGARDING THE TIMING WHEN
18 THE NEW CAPACITY WILL BE NEEDED IN ARIZONA?

19 A. For the purpose of these calculations, I assumed that the new capacity will be
20 needed in 2000. In other words, I assumed that from 2000 and onward, the
21 market price of electricity in Arizona will be equal the unit cost of an optimal mix
22 of new capacity.

23

1 Q. WHY HAVE YOU ASSUMED THAT THERE WILL BE A NEED TO ADD
2 NEW CAPACITY TO EACH UTILITY'S SYSTEM IN THE YEAR 2000?

3 A. My assumption is based on the long-term forecast of the electric utility industry
4 development in the Western Systems Coordinating Council/RA (Region 12) region
5 prepared by Energy Information Administration (EIA). In its 1997 Annual Energy
6 Outlook (AEO-97), EIA shows unplanned additions of CC and CT units of
7 relatively small magnitude (about 120 MW of new CC capacity and 180 MW of
8 new CT capacity) in that region starting in 1996. EIA projects further annual
9 additions of new CC and CT capacity such that between 1996 and 2000,
10 approximately 1500 MW of new CC capacity and 880 MW of new CT capacity
11 will be added to the RA system. It is important to note that year 2000 is the first
12 year in which only CC capacity is added to the system and no CT capacity. This
13 indicates that effective in the year 2000, the regional electricity market will need
14 mostly additional baseload capacity and no peaking capacity. Therefore, it is safe
15 to assume that starting this year almost all incremental load has to be served by
16 newly added capacity. This assumption justifies the reliance on unit cost of an
17 optimal CC/CT mix as a lower bound for the market price in the year 2000.

18
19 Q. DID YOU RELY ON THIS METHODOLOGY IN DEVELOPING MARKET
20 PRICE PROJECTIONS FROM 2000 ONWARD FOR ALL UTILITIES IN
21 ARIZONA?

22 A. Yes, I basically used this methodology for all three utilities, with one minor
23 exception. I used this methodology for developing market price projections for

1 two companies – APS and TEP. However, I did not have all the necessary load
2 data for SRP. Therefore, for the purpose of estimating SRP's stranded costs, I
3 assumed that in each year from 2000 onward its projected market price be equal to
4 the average of market price projections for APS and TEP. Since these two market
5 price projections were almost the same, this ought to be a good approximation for
6 SRP.

7
8 Q. WHAT ASSUMPTION DID YOU MAKE REGARDING THE MARKET
9 PRICE OF ELECTRICITY BETWEEN 1996 AND 2000?

10 A. I assumed that in 1996 the wholesale market price of electricity would be equal to
11 the average price of purchased power paid by each utility in that year. This is an
12 assumption that tends to overestimate stranded costs because the bulk of these
13 power purchases are non-firm and this average price substantially underestimates
14 the price of wholesale power which might have been observed if the electricity
15 market became fully deregulated and competitive in Arizona in 1996. My
16 estimated market price in the 3 years between 1996 and 2000 is based on a simple
17 interpolation of the estimated price for 1996 and the CC/CT based price in 2000.

18
19 Q. WHAT ASSUMPTIONS AND DATA SOURCES DID YOU USE TO
20 PROJECT THE UNIT COSTS OF NATURAL GAS AT WHICH IT WILL BE
21 AVAILABLE AS A FUEL FOR NEW CT AND CC PLANTS?

22 A. I developed a forecast of appropriate natural gas prices in two steps. First, I
23 started with a forecast price of natural gas for power generation in the Mountain

1 Region of the U.S. developed by EIA in AEO-97. Second, I increased this
2 forecast by factor of 12 percent to reflect the fact that historical prices of natural
3 gas use for power generation in Arizona were on average 12 percent higher than
4 similar prices in the entire Mountain Region in recent years, as shown in Exhibit
5 RAR-10.

6

7 Q. DID YOU MAKE ANY FURTHER ADJUSTMENTS TO THIS ESTIMATED
8 WHOLESALE MARKET PRICE OF ELECTRICITY?

9 A. Yes, I included two adders to reflect: 1) FERC Order 888 ancillary services worth
10 1 mill per kWh, and 2) a transmission and distribution line loss adder appropriate
11 for each company.

12

13 Q. HOW DID YOU OBTAIN THE BASE YEAR MARKET PRICE FOR RETAIL
14 GENERATION SERVICES THAT YOU USED IN THE PROJECTIONS OF
15 EACH COMPANY'S POTENTIAL STRANDED COSTS?

16 A. To obtain the base year market price for retail generation services that I used in the
17 projections of the Company's potential stranded costs, I added to the total
18 wholesale price a retail margin of 0.77 mills per kWh which I discuss in Section
19 4.B of this testimony.

20

21 Q. WHERE IN YOUR TESTIMONY COULD YOUR MARKET PRICE
22 CALCULATIONS BE FOUND?

1 A. Market price calculations for the Arizona Public Service Company and for Tucson
2 Electric Power are presented on pages 4-6 of Exhibit RAR-4 and Exhibit RAR-8,
3 respectively. Market price calculations for SRP are presented on pages 4 and 5 of
4 Exhibit RAR-6.

5

6 Q. DID YOU DEVELOP ANY ALTERNATIVE PROJECTIONS OF THE RETAIL
7 MARKET PRICE FOR THE PURPOSE OF COMPUTING STRANDABLE
8 COSTS?

9 A. Yes. In addition to the forecast described above (Base Case Scenario), I
10 developed two alternative market price projections for each Company – a High
11 Market Price Scenario and a Low Market Price Scenario. Under the High Market
12 Price Scenario, I simply increased the projected market price by 5 percent in each
13 year from 2000 onward. Similarly, under the Low Market Price Scenario, I
14 reduced the projected market price by 5 percent in each year from 2000 onward.
15 In both cases I used the same starting point for the retail market price in 1996, and
16 I interpolated between the 1996 price and the year 2000 price in both the High and
17 Low Market Price Scenarios.

18 **F. Projections of Regulated Generation Rates**

19 Q. HOW DID YOU FORECAST THE UNBUNDLED GENERATION SERVICE
20 RATE UNDER THE ASSUMPTION THAT CURRENT REGULATION
21 CONTINUED FOR EACH COMPANY BEYOND 1996?

22 A. For the purpose of my analysis of stranded costs, I simply assumed that the
23 unbundled generation service rate would stay constant in nominal dollars over the

1 25-year period 1996-2020 for TEP and SRP. By assuming that this unbundled
2 rate would remain constant, I am implicitly assuming a trade-off that would impact
3 revenue requirements between increasing fuel and O&M costs over time, and
4 depreciating generating assets. This assumption also reflects the fact that the
5 market price for purchased power will likely be lower than embedded generation
6 costs for several years into the future, but will then begin to increase. In order to
7 improve on this assumption, I would need to utilize long-run financial forecasts of
8 each utility, which were not available to me.

9 For APS I assumed that, beginning in year 2004, the regulated generation
10 rate will increase at 1.0 percent per year, after remaining constant from 1998-2003.
11 This increase was assumed to result from the end of the rapid depreciation of most
12 of the Company's regulatory assets.

13
14 Q. WHAT ASSUMPTIONS DID YOU MAKE TO FORECAST SALES
15 VOLUMES OF EACH COMPANY BEYOND 1996?

16 A. I escalated each of APS' and TEP's base year sales volumes at an annual rate
17 which reflected that Basecase sales forecast in their 1995 IRP filings. For SRP I
18 used their actual growth rate in sales for 1985-1995.

5. STRANDED COSTS RESULTS

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ESTIMATES OF
POTENTIAL STRANDED COSTS FOR THE THREE UTILITIES.

A. I present the summary results of my stranded cost analyses in Exhibit RAR-2. As shown in this exhibit, the potential net present value of stranded costs in 1998 dollars vary substantially with market price scenario, and with the time frame over which estimates are made. This is a typical result. However, it is important to note that potential stranded costs for APS and for SRP are consistently negative in all scenarios over the time frame 1998-2020; whereas strandable costs for TEP are positive in the period 1998-2020 in all scenarios. The time period 1996-2020 is sufficiently long to represent a reasonable period over which to compute stranded costs, since most if not all generation assets will last this long. A similar pattern could be observed over a shorter, 15-year period of time, 1998-2012, with one exception – positive stranded costs for APS result in the low market price scenario, and slightly positive stranded costs result for APS in the Basecase. Thus, TEP's stranded costs are also positive if the calculation is made over the 15-year period from 1998-2012. However, the 15-year period 1998-2012 is such a short time period over which to measure strandable costs that the small positive value of \$102 million (PV) for APS in the Basecase should not be taken as significant when compared to the strongly negative \$838 million (PV) result obtained if the calculation is continued through 2020.

1 In short, these results lead to a conclusion that the deregulation of
2 electricity market will likely create no materially significant stranda-
3 ble costs for APS or SRP. However, TEP will likely have a significant level of stranda-
4 ble costs.

5 Q. PLEASE DISCUSS YOUR ESTIMATES OF POTENTIAL STRANDED
6 COSTS COMPUTED OVER THE 15-YEAR PERIOD 1996 THROUGH 2010.

7 A. I made these calculations mostly for illustrative purposes only. The period 1996-
8 2010 is not an appropriate time period over which to compute stranded costs.
9 Indeed, this period covers two past years, 1996 and 1997. The results show that
10 ratepayers have already paid for about \$556 million, \$456 million, and \$434
11 million in stranda-
12 ble or uneconomic costs for APS, TEP, and SRP, respectively, in
13 just those two years. I simply wanted to include these two years in my analysis
14 because available base year data start in 1996. Furthermore, as I stated earlier, my
15 market price estimates in these two years are likely to substantially understate the
16 price of power which would have been observed if electricity market became fully
17 deregulated and competitive in Arizona in 1996. This is especially true for TEP
18 which was buying power primarily on a non-firm basis at a low price of 1.59 cents
19 per kWh. Finally, by beginning my analysis in 1996, one can see how fast
20 ratepayers are paying for uneconomic generation costs during 1996 and 1997
21 when compared with the overall long-term magnitude of these stranda-
22 ble costs.
23 (See page 1 of Exhibits RAR-4, RAR-6, and RAR-8.

22 Q. PLEASE DISCUSS YOUR ESTIMATES OF POTENTIAL STRANDED
23 COSTS COMPUTED OVER THE 15-YEAR PERIOD 1998 THROUGH 2012.

1 A. Again, I believe that these results provide an **upper limit** on the potential stranded
2 costs for each company for each market price scenario. Certainly, a shorter time
3 period should not be relied on for the purpose of setting a stranded cost recovery
4 charge. For example, APS' strandable costs in the period 1998-2012 range from
5 negative \$417 million under the High Market Price Scenario to positive \$559
6 million under the Low Market Price Scenario. Thus, strandable costs for APS
7 roughly center around zero even when computed over this relatively short time
8 period.

9
10 Q. PLEASE DISCUSS YOUR ESTIMATES OF POTENTIAL STRANDED
11 COSTS COMPUTED OVER THE PERIOD 1998 THROUGH 2020 WHEN
12 COMPARED WITH THOSE COMPUTED OVER THE PERIOD 1998
13 THROUGH 2012.

14 A. The results for 1998-2020 illustrate that the potential stranded costs decrease
15 significantly with further extension of the period used for the stranded cost
16 calculations. This result simply reflects the fact that the farther out one goes in
17 time, the higher retail market prices are likely to be with respect to projected
18 regulated prices for generation.

19
20 Q. WHICH EXHIBITS SUPPORT THE DEVELOPMENT OF THESE
21 STRANDABLE COST ESTIMATES?

22 A. Exhibits RAR-4 and RAR-5 support my results for APS; Exhibits RAR-6, and
23 RAR-7 support results for SRP, and Exhibits RAR-8 and RAR-9 support results

1 for TEP. As these exhibits differ only with respect to specific utility data and to
2 the +/- 5 percent adjustment to market price of generation assumed for the
3 stranded cost calculation, it will suffice to focus only on Exhibit RAR-4 here in
4 order to explain all six exhibits.

5
6 Q. PLEASE TURN TO AN EXAMINATION OF EXHIBIT (RAR-4).

7 A. In Table 1, Exhibit RAR-4 page 4, I present a calculation approximating the least-
8 cost price of supplying energy to meet APS' customer demands using the mix of
9 new CC and CT power plants, as I explained earlier. The result is a wholesale
10 market price of 3.31 cents per kWh in 1996 dollars, and a retail market price of
11 4.08 cents per kWh.

12 In Table 2, Exhibit RAR-4 page 3, I present a summary of the calculation
13 of the unbundled cost of generation, transmission, distribution, and customer-
14 related services based on APS' 1996 costs. The 1996 unbundled price of
15 generation was calculated to be 5.02 cents per kWh under current regulation. This
16 unbundled generation price becomes the baseline generation price against which
17 the retail market price is compared to evaluate potential stranded costs. Again, as
18 I stated earlier, in making our projections I assumed that the generation component
19 of current rates would remain constant in nominal terms for 8 years, and then
20 would increase at 1.0 percent per year.

21 In Tables 3a and 3b, Exhibit RAR-4, pages 2 and 1, respectively, I present
22 the yearly calculation of potential stranded costs for APS. The differences
23 between the market price and generation price listed in Table 3a become an input

1 to Table 3b. In Table 3b, the price differences represent the per-kWh strandable
2 costs. These unit strandable costs are multiplied by the forecasted retail Arizona
3 jurisdictional sales for each year to determine an annual strandable cost estimate.
4 These yearly strandable cost estimates are summed, and the net present value (in
5 1998 dollars) of three streams of retail strandable costs is determined, one for a
6 15-year period 1996-2010, another for a 15-year period 1998-2012, and a third
7 one for a 23 year period, 1998-2020.

8 A final step in calculating the projected strandable costs that are computed
9 *externally* to the SCM, is to add the net present value of generation-related
10 regulatory assets not currently in rate base to the estimate of projected strandable
11 costs already in rates. My initial estimate of the present value of these regulatory
12 assets for APS is about \$110.3 million.

13 Table 4, Exhibit RAR-4, page 5, and page 6 of Exhibit RAR-4 presents a
14 summary of many of the assumptions made in modeling APS' estimated strandable
15 costs. This provides a complete overview of all key financial and modeling
16 assumptions, and is simply for reference purposes. No calculations are presented
17 in this table.

18
19 Q. PLEASE COMMENT ON THE FACT THAT YOUR ESTIMATES OF
20 STRANDED COSTS ARE QUITE SENSITIVE TO THE MARKET PRICE
21 PROJECTION UNDERLYING EACH SCENARIO.

22 A. It is important to note that my results for strandable costs are preliminary estimates
23 that can and should be refined based on a more detailed accounting analysis of all

1 three companies' unbundled rates, regulatory assets, and more accurate forecasting
2 of future unbundled generation rates under regulation. Assuming that a true-up
3 procedure is adopted for the recovery of stranded costs, the current uncertainty in
4 market prices will not matter significantly, since the actual stranded costs collected
5 from ratepayers, if any, can be adjusted when actual retail market prices for
6 generation become known in the future. Thus, the Commission and other
7 stakeholders should focus their attention next on the most accurate unbundling of
8 utility rates possible in order to derive the most accurate possible projection of
9 each company's generation costs under regulation. As part of the unbundling
10 process, the Commission should make sure that all past costs including A&G
11 expenses, that were caused by the construction or operation of generation
12 facilities, or the contracting for purchased power, are allocated to the generation
13 component of rates, and are removed from transmission and distribution rates.

14
15 Q. WHAT IS YOUR MAJOR CONCLUSION BASED ON THE RESULTS OF
16 THESE ANALYSES?

17 A. Again, the major conclusion of my determination of stranded costs is that the
18 deregulation of the electricity market will create no materially significant amount
19 of positive strandable costs in Arizona, except for TEP. This implies that, if retail
20 competition is initiated in Arizona, there may need to be a **negative** stranded cost
21 recovery charge put into place for APS and SRP in order to prevent their
22 ratepayers from paying more for electric generation over the next 10-15 years than
23 they would have if the regulation of generation prices had continued during this

1 time. Even if the stranded cost recovery charge is negative, the same basic policies
2 can be followed as recommended in Section 6 below. In particular, a negative
3 stranded cost recovery charge still needs to be trued-up periodically in order to
4 ensure that ratepayers do not pay more than they would under continued
5 regulation of generation prices. One reason why the stranded costs of APS and
6 SRP are so strongly negative from 1998 forward is that ratepayers have already (or
7 will have soon) paid the uneconomic costs embedded in each utility's generation
8 mix in the past. This is typical since the costs of most uneconomic power plant
9 investments are front-loaded in the early years due to utility accounting practices.
10 Once ratepayers have paid for the uneconomic costs of these power plants, it
11 would be unfortunate if they do not get the longer-run benefits of these plants
12 when the cost of their output is lower than market priced alternatives.
13

1 **Issue No. 3.A**

2 Q. WHAT IS YOUR RECOMMENDED CALCULATION METHODOLOGY AND
3 WHAT ASSUMPTIONS SHOULD BE MADE IN DETERMINING THE
4 MARKET CLEARING PRICE?

5 A. Stranded costs should be defined as the difference between the competitive market
6 value of retail generation services and the embedded cost of a utility's generation
7 assets. Therefore, the stranded costs for all Affected Utilities including SRP should
8 be calculated using the administrative valuation approach unless a sale of the assets
9 actually occurs. This approach compares projections of the utility's revenues for
10 electric generation if generation prices were deregulated, and projections of the
11 utility's revenues for electric generation if generation prices were continued to be
12 regulated based on the utility's embedded costs of generation. The difference
13 between these two reference streams would, then, be the revenues "lost" if retail
14 access were implemented. This difference should also be present valued. The result
15 is an estimate of net stranded costs across all generation resources.

16 The administrative valuation approach leads to knowing what the utility's
17 total economic and uneconomic embedded cost of generation is and, therefore,
18 helps to determine the correct unbundling of the utility's current embedded cost-
19 of-service. Electric service costs should initially be unbundled into total
20 generation-related ancillary services, transmission and transmission-related
21 ancillary services, distribution, and customer services (such as metering and
22 billing). Through use of the administrative valuation approach, the economic

1 generation and generation-related ancillary service costs would also be separated
2 from the uneconomic or stranded generation costs.

3

4 Q. SHOULD THE "STRANDED COST" METHODOLOGY COMPUTE
5 UNECONOMIC COSTS THAT ARE ACTUALLY STRANDED BY THE
6 ONSET OF RETAIL COMPETITION, OR SHOULD THE METHODOLOGY
7 YIELD THE TOTAL FOR ALL STRANDABLE OR UNECONOMIC COSTS
8 AS OF A SPECIFIC DATE?

9 A. I believe the calculation methodology should yield total *potentially* stranded or
10 strandable costs as of a specific date, not just costs actually stranded due to
11 customers leaving the utility's system for an alternative supplier. As indicated
12 above, this assumes that the utility would be forced to charge customers a retail
13 market price for all of their generation in a fully competitive market, regardless of
14 what its embedded generation costs are. As discussed above, the stranded cost
15 calculation methodology must focus on the retail price of electricity and not just
16 the wholesale market price which would be just one component of a retail price.
17 After all, once unbundled correctly, the generation component of current rates is
18 the retail price that customers are paying for generation services. Thus, the market
19 price that this generation-related revenues stream is being compared to must also
20 be a retail price for generation services, not a wholesale price.

21

22 Q. HOW SHOULD THE MARKET PRICE OF POWER BE DETERMINED?

1 A. The estimation of a retail market price should explicitly be based on the
2 assumption that in a competitive retail market, the Affiliated Utilities would likely
3 charge all customers this market price for generation services. The average market
4 price represents the energy and demand costs necessary to serve the utility's entire
5 load. Therefore, the retail market price represents the average retail cost of power
6 in the region to serve a particular load based on its load factor and other seasonal
7 characteristics, as opposed to just the marginal wholesale cost in the market at
8 certain time-periods. A reasonably accurate wholesale market clearing price should
9 rely on cost information for a new natural gas combustion turbine and a new
10 natural gas combined cycle plant to determine a market price based on the optimal
11 mix of CTs and CCs to serve a particular utility's entire load profile. Using the
12 cost of CCs and CTs to calculate the market price is likely to represent a "low
13 case" market price value, since it is unlikely that the wholesale market price for
14 generation would be less than the cost of new CCs and CTs. This issue was
15 discussed further in Section 4.B. of this testimony.

16 In developing estimates of the retail market price for power, taking into
17 account only the wholesale price of power is insufficient, as noted above. The
18 correct valuation should be based on retail prices for generation services to the
19 customer, which are equal to wholesale prices plus a retail margin. In order to
20 provide retail generation services to end-use customers, alternative suppliers will
21 have to incur many costs not embedded in market prices of bulk or wholesale

1 power, such as administrative and general expenses, billing service costs, customer
2 service costs, marketing and other transaction costs, as discussed above.¹¹

3

4 **Issue No. 3**

5 Q. WHAT COSTS SHOULD BE INCLUDED AS PART OF 'STRANDED COSTS'
6 AND HOW SHOULD THOSE COSTS BE CALCULATED?

7 A. As discussed previously, stranded costs should include the following categories of
8 costs that are currently being incurred by utilities:

- 9 • generation assets and generation O&M costs
- 10 • purchase power agreements
- 11 • fuel contracts
- 12 • regulatory assets and liabilities
- 13 • generation-related A&G

14 A portion of a utility's power plant costs could become unrecoverable if
15 market prices for retail generation services are not high enough to support full
16 recovery of variable production costs (including fuel), fixed operation and
17 maintenance costs, and all of the capital-related costs and generation-related A&G
18 costs and regulatory assets and liabilities.

19 Generation-related regulatory assets include (but are not limited to)
20 accounting reserves for various types of deferred costs related to: 1) the phase-ins
21 of new power plants, 2) nuclear plant decommissioning costs, 3) deferred income

¹¹ See RUCO's Response to the Stranded Costs Working Group Report, September 25, 1997, page 9.

1 taxes, and 4) pension funds. Some of these regulatory assets may already be
2 included in a utility's current rates, while others may not. Under traditional
3 regulation, a utility would ultimately be likely to collect regulatory assets not yet in
4 ratebase. Regulatory liabilities that are also not yet in rates might also impact
5 stranded costs. Thus, regulatory assets and liabilities, including those not yet in
6 rates, will contribute to stranded costs.

7 In addition, generation-related long-term legal obligations, such as
8 purchased-power contracts and fuel supply contracts, could contribute to stranded
9 costs if they exceed competitive market prices for comparable goods and services.

10 Finally, the utility's *current costs* of performing necessary functions and
11 providing services that get wholesale bulk power to the retail end user (generation-
12 related A&G costs) may be above or below the costs that competitive suppliers
13 will incur to provide comparable retail generation services. A utility's above-
14 market generation retailing costs will also contribute to stranded costs. On the
15 other hand, if generation-related A&G costs are below the future level of the retail
16 margin as is much more likely to be the case, stranded costs would be reduced.

17
18 **Issue No. 4**

19 Q. SHOULD THERE BE A LIMITATION ON THE TIME FRAME OVER
20 WHICH STRANDED COSTS ARE CALCULATED?

21 A. Yes, there should be a limitation on the time frame over which stranded costs are
22 calculated. Stranded cost estimates can be very sensitive to the time period over
23 which they are calculated. The sensitivity occurs because stranded costs are based

1 on the difference between the estimated embedded costs of generation and the
2 estimated market prices of generation in each year during a specified time period,
3 and these differences are likely to decrease over time and will most likely reverse.
4 For example, the embedded cost-based generation rates for a utility may be
5 significantly above the market price of power in the first year of the time period
6 utilized. However, for most utilities, the embedded costs of existing generation
7 service would be expected to decline over time due to depreciation and the fact
8 that any new demand would be met with purchases from the market at market
9 prices rather than with the construction of new utility-owned plants. Market prices
10 may start low in the first year of the time period due to excess capacity, but will
11 likely increase over time due to the tightening of available capacity. Therefore, the
12 gap between embedded cost-based generation rates and market prices for power
13 would narrow each year. If this trend of embedded cost-based generation rates
14 declining faster than estimated market prices continued, then at some point
15 embedded cost-based generation rates would fall below the market price for
16 power. This would mean that there would be negative stranded costs on an annual
17 basis in some of the later years. Therefore, if the stranded cost calculation is done
18 over a reasonably long period, then the net stranded costs may be lower than if
19 calculated over a shorter time period. To provide a fair estimate of net stranded
20 costs, the calculation must be made over the expected lives of the generation
21 assets, not a near-term period such as five years or less. Thus, unless demonstrated
22 otherwise, stranded costs should be computed using a time period of at least 15

1 years, and perhaps as much as 25 years, depending on the expected life of the
2 generation resources of a particular utility.

3

4 **Issue No. 3.B**

5 Q. WHAT ARE THE IMPLICATIONS OF FINANCIAL ACCOUNTING
6 STANDARDS NO. 71 RESULTING FROM THE RECOMMENDED
7 STRANDED COST CALCULATION AND RECOVERY METHODOLOGY?

8 A. The Statement of Financial Accounting Standards No. 71, *Accounting for the*
9 *Effects of Certain Types of Regulation*, defines a regulated entity, contains
10 standards public utilities' financial statements must comply with, and allows
11 regulators to create assets (regulatory assets) by deferring to future periods (by
12 making recoverable in rates) certain current costs which would otherwise be
13 charged to expenses under Generally Accepted Accounting Principles. Since SFAS
14 No. 71 will be discontinued due to electric utility restructuring¹², and utilities
15 would essentially have to charge to retained earnings all generation-related
16 regulatory assets not in rates¹³, this could have a significant impact on stranded
17 costs. The nature of an asset may change due to the characteristics of its ultimate
18 cost recovery¹⁴, meaning that it is possible for the asset to continue being carried

¹² See Statement of Financial Accounting Standards No. 101, *Accounting for Discontinuation of Application of SFAS No. 71*.

¹³ Docket No. U-0000-94-165: Report to the Arizona Corporation Commission- In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona-Stranded Cost Working Group Report, p. 56.

¹⁴ Docket No. U-0000-94-165: Report to the Arizona Corporation Commission- In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona-Stranded Cost Working Group Report, p. 58.

1 on the books of the utility as a distribution-based regulatory asset. If the ACC
2 allows these assets to be recovered, they should be unbundled as part of stranded
3 costs for generation.

4

5 **Issue No. 7**

6 Q. SHOULD THERE BE A TRUE-UP MECHANISM AND, IF SO, HOW
7 WOULD IT OPERATE?

8 A. Yes, there should be a true-up mechanism and process established for adjusting
9 stranded costs. Adjustment (or true-up) of initial stranded cost estimates would
10 ensure that electric restructuring in Arizona is carried out in the public interest, and
11 would ensure that stranded costs actually paid by ratepayers more accurately
12 reflected actual retail market prices as they become known. This is critical in order
13 to prevent ratepayers from paying certain stranded costs twice; once in a stranded
14 cost recovery charge and once in the market price for generation. The amount of
15 stranded cost recovery from ratepayers should be calculated administratively and
16 trued-up annually (or at least bi-annually) to account for both actual retail market
17 prices of generation and actual changes in what the regulated cost of generation
18 would have been. The Commission could make a final review of stranded cost
19 recovery at the end of the transition period to retail access, comparing the stranded
20 costs being recovered through the Competitive Transition Charge (CTC) with the
21 stranded costs actually incurred over the transition period based on the actual
22 market prices experienced for retail generation services for each rate class. To

1 repeat, at least three aspects of original derivation of the CTC may cause stranded
2 cost recovered to differ from those incurred: (1) the cost assumptions used in
3 preparing the stranded cost estimates (i.e. the market price) were inaccurate, (2)
4 the forecast of electricity sales used to set the CTC (on a per-kWh basis) over the
5 transition period was inaccurate, and (3) the projection of the unbundled
6 generation component of current rates was inaccurate. These aspects should be
7 periodically updated with historical information when reconciling the amount of
8 stranded costs recovered in the true-up process.

9 A true-up mechanism not only protects ratepayers from paying too much in
10 stranded cost recovery charges, but also protects ratepayers from the negative
11 price effects (higher than competitive prices) of an immature competitive power
12 market and/or from the exercise of market power.

13
14 **Issue No. 9**

15 Q. WHAT FACTORS SHOULD BE CONSIDERED FOR THE 'MITIGATION' OF
16 STRANDED COSTS?

17 A. Utilities should be required to reduce potentially strandable generation costs as
18 much as possible *before* Arizona takes steps towards allowing recovery of
19 stranded costs. The utility should first focus attention on bringing the embedded
20 cost of generation (including operating costs) closer to the market price for
21 generation. Appropriate mitigation measures should fall into the category of cost
22 reduction. Both cost shifting and revenue enhancement through load growth are
23 not true mitigation measures. Reasonable and prudent mitigation efforts can vary

1 between utilities and should therefore be evaluated on a case-by-case basis.

2 However, the list of possible mitigation categories is long, and an evidentiary

3 hearing may be necessary to identify all utility-specific mitigation potential. The list

4 of possible mitigation categories includes:

- 5 • restructuring or refinancing existing debt
- 6 • renegotiating or buying out of power contracts, including non-utility
- 7 generation (NUG) contracts, that do not have termination or release
- 8 clauses
- 9 • selling excess generating capacity if it has more value in the market than it
- 10 does to the current owner
- 11 • retiring uneconomic generating facilities if their operating costs exceed the
- 12 price of replacing their output.
- 13 • improving economic efficiency and productivity of generation units

14 Thus, stranded cost mitigation measures should focus to the greatest extent
15 possible on cost reduction. These measures should improve equity and/or
16 economic efficiency, whereas cost shifting and revenue enhancement may not.

17
18 Q. PLEASE EXPLAIN WHY YOU STATE THAT STRANDED COST
19 MITIGATION SHOULD NOT INCLUDE COST SHIFTING MEASURES.

20 A. Cost shifting measures do not constitute genuine attempts at mitigating stranded
21 costs. Instead, these measures shift costs between utility shareholders and
22 ratepayers, among customer classes, or among electricity services (such as
23 between deregulated and regulated services). Examples of cost shifting include

1 voluntary write-downs of excessive generating plant costs and accelerated
2 depreciation schedules of plant or regulatory assets.

3

4 **Issue No. 6**

5 Q. HOW AND WHO SHOULD PAY FOR 'STRANDED COSTS' AND WHO, IF
6 ANYONE, SHOULD BE EXCLUDED FROM PAYING STRANDED COSTS?

7 A. Payment of stranded costs should be made by all customers in each service
8 territory according to tariff class. The charges for stranded cost recovery over time
9 for each rate class should be determined through traditional cost-of-service rate
10 design principles, and in particular, cost causation. For example, the economic
11 portion of generation costs could be appropriately allocated to each customer class
12 according to cost causation principles, as embodied in the inter-class cost
13 allocators used in the last rate case. Then, the difference between this allocation of
14 economic generation costs by customer class and the allocation of total generation
15 costs by customer class that occurred in the last rate case would represent a fair
16 allocation of stranded costs to each customer class. These principles applied would
17 balance an energy charge and a demand charge so that equity is maintained. Tariffs
18 for each rate class should continue to have the same billing determinants as they
19 currently have. This approach would lead to a revenue neutral unbundling.

20 The payment of stranded costs should be made through a non-bypassable,
21 nondiscriminatory "wires" charge or competition transition charge (CTC) which
22 would tie the collection of stranded generation costs to the continued use of
23 transmission or distribution service. The CTC would not vary, then, from supplier

1 to supplier. Purchasing power from a competitive generation source should not
2 impact a retail customer's obligation to pay for stranded costs. Competing
3 suppliers would, therefore, have no competitive advantage or disadvantage based
4 on recovery of the existing generation owner's stranded costs.

5 The CTC should be charged to customers on the basis of cost causation, as
6 a natural consequence of using the revenue neutral approach to unbundling, as
7 described above. The methodology implies that for those customer classes having
8 both demand and energy-based components of its tariff, the CTC will also have
9 both demand and energy components.

10
11 Q. RELATED TO THE PREVIOUS QUESTION REGARDING HOW AND WHO
12 SHOULD PAY FOR 'STRANDED COSTS' IN GENERAL, SHOULD
13 STRANDED COST BE SHARED BETWEEN RATEPAYERS AND
14 STOCKHOLDERS?

15 A. Yes, in general, positive stranded costs should be shared between the ratepayers
16 and stockholders. From a policy perspective, the key factor to consider in
17 determining how to share stranded costs is equity. Considerations of equity would
18 initially indicate that a 50/50 sharing would be appropriate. The extent to which
19 the recovery of stranded costs is shared between ratepayers and utility
20 stockholders is critical to lowering rates for all customers in the short- to medium-
21 term under retail competition. First, the ACC should consider on a utility-by utility
22 basis what factors led to stranded costs that might have been significantly under
23 the control of each utility, and what ratemaking treatment the assets with

1 uneconomic costs have received since their inclusion in the utility's ratebase. Then,
2 the ACC should determine whether stockholders should be held responsible for
3 substantially more than 50 percent of stranded costs. The Commission should first
4 decide on the appropriate percentage sharing for each generating asset which
5 contributes to stranded costs, based on the causes of the stranded costs and the
6 historic ratemaking treatment of each asset. Then the Commission should weigh
7 these results together to get an overall system-wide percentage sharing. Retail
8 ratepayers should not be held responsible for more than 50 percent of a utility's
9 prudent stranded generation costs, unless special considerations are necessary to
10 maintain the financial integrity of the utility. Recovery should be based on a lower
11 rate of return through use of a bond rate, not an equity rate which includes a risk
12 premium.

13

14 **Issue No. 5**

15 Q. SHOULD THERE BE A LIMITATION ON THE RECOVERY TIME FRAME
16 FOR 'STRANDED COSTS'?

17 A. The time frame for stranded cost recovery should be determined prior to
18 commencing the recovery process. Assuming that a wires charge would be used
19 for recovery, the time frame should depend on 1) the magnitude of the net present
20 value of the utility's stranded costs that need to be recovered from ratepayers, 2)
21 the estimated level of electricity demand on the utility's distribution system in
22 future years, 3) the utility's discount rate, and 4) keeping the strandable cost
23 recovery charge within reasonable limits so that a customer's total electric rate

1 relative to the rate currently paid under regulation is reduced to an appropriate
2 level. Generally, the longer the period allowed for recovery, the smaller the
3 stranded cost recovery charge would be. A longer recovery period could,
4 therefore, allow for greater rate reductions in the early years of the recovery
5 period. But a longer recovery period also may delay the enjoyment of the full
6 potential savings brought about through a competitive generation market.

7
8 Q. GIVEN ALL RELEVANT CONSIDERATIONS, WHAT MAXIMUM TIME
9 FRAME WOULD YOU RECOMMEND FOR STRANDED COST
10 RECOVERY?

11 A. Based on the trade-offs and considerations just mentioned, I recommend that the
12 time frame for recovering stranded costs from ratepayers be less than ten years.
13 Ten years should be the maximum recovery period, even for utilities with high
14 stranded costs. However, if stranded costs are modest relative to the size of a
15 utility, then all stranded costs should be able to be recovered within a five year
16 period, or less. For Arizona, this should imply full recovery by January 1, 2003,
17 which is the start date for full retail access. If necessary, the recovery charge
18 should be designed to be constant in real dollars, thus enabling near-term rates to
19 be lower than if the stranded cost recovery charge were levelized in current
20 dollars. The recovery period, the recovery mechanism, and the amount of sharing
21 should be structured so that in the early years of the recovery period, retail
22 ratepayers taking the standard offer service see a rate reduction. Note that even if
23 strandable costs are non-existent, just re-setting generation rates for Standard

1 Offer Service at a market-based retail rate would likely allow for a significant rate
2 reduction.

3

4 **Issue No. 8**

5 Q. SHOULD THERE BE PRICE CAPS OR A RATE FREEZE IMPOSED AS
6 PART OF THE DEVELOPMENT OF A STRANDED COST RECOVERY
7 PROGRAM AND IF SO, HOW SHOULD IT BE CALCULATED?

8 A. I recommend that a price cap, as opposed to a rate freeze, be imposed by the ACC
9 during the transition period. Capping the rate for the standard offer generation
10 service at the lower of the generation rate that would have been charged to each
11 customer class if retail competition had not been introduced in Arizona, or the
12 market price for retail generation services appropriate to that customer class is
13 recommended. If this is done during the transition period, it would guarantee that
14 during the transition to retail competition, customers will be at least as well off as
15 they would have been under continued cost of service rate regulation. This will
16 also ensure that ratepayers do not pay for any generation costs twice, once in the
17 rates for standard offer of service and again in the stranded cost recovery charge.
18 This approach will allow all customers to enjoy the rate benefits of retail
19 competition during the transition period. Use of a market price to set the retail
20 generation cap will also provide a degree of customer protection in the event that a
21 utility wishes to deregulate any of the generation assets used to serve standard
22 offer customers.

23

1 **Issue No. 1**

2 Q. SHOULD THE ELECTRIC COMPETITION RULES BE MODIFIED
3 REGARDING STRANDED COSTS, IF SO, HOW?

4 A. Yes, I believe that the set of policies and principles that I have recommended
5 above imply that many modifications to the electric competition rules need to be
6 made. The following questions pertain solely to the changes that I am
7 recommending in the Rules.

8

9 Q. DO YOU AGREE WITH THE DEFINITION OF STRANDED COSTS IN THE
10 RULES?

11 A. No, I recommend that the definition of stranded costs be clarified. In Section R14-
12 2-1601, stranded costs are defined as,

13 “the verifiable net difference between a) the value of all the prudent
14 jurisdictional assets and obligations necessary to furnish electricity
15 (such as generating plants, purchased power contracts, fuel
16 contracts, and regulatory assets), acquired or entered into prior to
17 the adoption of this Article, under traditional regulation of Affected
18 Utilities, and b) the market value of those assets and obligations
19 directly attributable to the introduction of competition under this
20 Article.”

21

22 This definition of stranded costs only includes changes in asset value due to the
23 introduction of competition under Article 16 of the Rules, but does not refer
24 directly to the total of the uneconomic costs associated with a utility's generation
25 resources as *strandable* costs that exist whether or not retail competition is
26 established. The existing uneconomic costs associated with a utility's generation
27 resources have already been incurred and are presently part of its regulated

1 embedded costs of service. Therefore, all existing uneconomic generation costs are
2 currently being recovered through the bundled rates paid by all retail customers.

3 These uneconomic costs are not stranded yet, but are strandable and could become
4 stranded if there is retail competition. Therefore, the definition of stranded costs in

5 Section R14-2-1601 should be reworded as:

6 “the uneconomic portion (net sunk generation costs plus
7 unavoidable prospective costs associated with a utility’s generation
8 that cannot be recovered in a competitive market) of a utility’s
9 costs for owning and operating its power plants, long-term
10 purchase power contract costs, fuel supply contract costs,
11 generation-related regulatory assets, and regulatory assets and
12 liabilities that are generation-related but are not recoverable under
13 competition as defined by the verifiable net difference between a)
14 the value of all the prudent jurisdictional assets, obligations and
15 costs necessary to furnish electricity, acquired or entered into prior
16 to the adoption of this Article, under traditional regulation of
17 Affected Utilities, and b) the market value of those assets and
18 obligations.”
19

20 Q. DO YOU RECOMMEND ANY CHANGES TO SECTION A or B of R14-2-
21 1607 ON THE RECOVERY OF STRANDED COSTS OF AFFECTED
22 UTILITIES?

23 A. Yes, I recommend the following modifications:

24 Section A states that,

25 “Affected Utilities shall undertake every feasible, cost-effective
26 measure to mitigate or offset stranded costs by means such as
27 expanding wholesale or retail markets, or offering a wider scope of
28 services for profit, among others.”
29

30 I disagree because I do not believe that increasing the total load by
31 expanding wholesale or retail markets is a proper mitigation measure. Expanding
32 sales does not necessarily reduce the total value of stranded costs. More

1 appropriate mitigation measures comprising cost reduction should be mentioned by
2 way of example in this article, including such measures as improving the economic
3 efficiency and productivity of generation plants, selling excess generating capacity,
4 and renegotiating or buying out of uneconomic power contracts, including non-
5 utility generation (NUG) contracts. Section A. should also make explicit the time
6 frame in which mitigation measures should occur. Utilities should be required to
7 reduce and mitigate potentially strandable generation costs as much as possible
8 before Arizona takes steps to allocate recovery of stranded costs. Therefore, I
9 would reword this section of the Rules to say the following:

10 "The Affected Utility shall take every feasible, cost-effective
11 measure to mitigate or reduce stranded costs before steps are taken
12 by the ACC to allocate recovery of stranded costs through cost
13 reduction measures such as improving the economic efficiency and
14 productivity of generation plants, selling excess generating capacity,
15 and renegotiating or buying out uneconomic power contracts,
16 including non-utility generation (NUG) contracts."
17

18 In addition, Section B states:

19 "the Commission shall allow recovery of unmitigated Stranded
20 Cost by Affected Utilities."
21

22 Unfortunately, this section appears to require 100 percent stranded cost
23 recovery after mitigation, implying that no sharing of stranded costs between
24 ratepayers and stockholders is appropriate. I strongly disagree with this aspect of
25 the Rules and believe that at the very least, the Rules must allow for the possibility
26 of sharing, as determined by the ACC. In fact, I advocate that stranded costs
27 should be shared between both ratepayers and shareholders.¹⁵ As discussed

¹⁵ It is important to note that taxpayers will also "pay" a portion of stranded cost recovery if some allocation is made to shareholders. Reduction of utilities' federal and state income taxes due to

1 earlier, allocating 50 percent to ratepayers and 50 percent of the stranded costs of
2 shareholders is a recommended baseline for stranded cost allocation. An important
3 factor in determining the appropriate sharing is how much ratepayers have already
4 paid (on a present value basis) toward stranded costs to Arizona's utilities. The
5 ACC should consider on a utility-by-utility basis what factors led to stranded costs
6 and what ratemaking treatment the assets with uneconomic costs have received
7 since their inclusion in the utility's ratebase. Therefore, this section of the Rules
8 should be reworded to say:

9 "The Commission shall consider, on a utility-by-utility basis, what
10 factors led to the existence of stranded costs, what ratemaking
11 treatment the assets with uneconomic costs have received since
12 their inclusion in the ratebase and, therefore, what the appropriate
13 percentage sharing between ratepayers and stockholders for each
14 generating resource which contributes to stranded costs should be,
15 and shall then allow for the recovery of the appropriate portion of
16 unmitigated stranded costs by Affected Utilities."
17

18 Q. DO YOU RECOMMEND ANY CHANGES TO SECTIONS C OR D of R14-2-
19 1607 ON THE RECOVERY OF STRANDED COSTS OF AFFECTED
20 UTILITIES?

21 A. No, I have no proposed changes to Sections C or D.
22

the partial write-off of stranded costs actually results in a sharing of those costs between the utility shareholders, ratepayers, and taxpayers. To the extent that taxpayers and electricity ratepayers are the same households or businesses, they may contribute to stranded cost recovery through two mechanisms.

1 Q. DO YOU RECOMMEND ANY CHANGES TO SECTION E, F, G or H of R14-
2 2-1607 ON THE RECOVERY OF STRANDED COSTS OF AFFECTED
3 UTILITIES?

4 A. I have no comments or proposed changes for Sections E, F or G. But, I do have
5 recommendations regarding Section H. Section H. states,

6 "An Affected Utility shall request Commission approval of
7 distribution charges or other means of recovering unmitigated
8 Stranded Costs from customers who reduce or terminate service
9 from the Affected Utility as a direct result of competition governed
10 by this Article, or who obtain lower rates from the Affected Utility
11 as a direct result of the competition governed by this article."
12

13 I agree that the ACC must approve stranded cost recovery charges for customers
14 who receive generation services from alternative suppliers to their local
15 distribution utility, but believe that use of a wires charge paid by all customers of
16 the distribution utility as part of a proper unbundling of rates will solve this
17 problem.¹⁶ The wires charge should be applied by the local distribution company,
18 and therefore stranded costs would be allocated to all customers being served by
19 the local distribution system. Both standard offer customers and those being
20 supplied by alternative suppliers as a result of competition will pay for stranded
21 costs on an equitable basis due to a wires charge. Therefore, Section H should be
22 reworded so that,

23 "Unmitigated Stranded Costs eligible for recovery shall be
24 recovered both from customers who reduce or terminate generation
25 service from the Affected Utility as a direct result of competition
26 governed by this Article by taking generation service from
27 alternative suppliers, as well as from customers who stay with

¹⁶ Thus far, all states have taken this approach.

1 standard offer service, through a non-bypassable, nondiscriminatory
2 wires charge.”
3

4 Q. DO YOU RECOMMEND ANY CHANGES TO SECTION I OF R14-2-1607 ON
5 THE RECOVERY OF STRANDED COSTS BY AFFECTED UTILITIES?

6 A. I offer the following comments on Section I. Section I begins with,

7 “The Commission shall, after hearing and consideration of analysis
8 and recommendations presented by the Affected Utilities, staff, and
9 intervenors, determine for each Affected Utility the magnitude of
10 Stranded Cost, and appropriate Stranded Cost recovery
11 mechanisms and charges, the Commission shall consider at least the
12 following factors:”
13

14 No. 1) The impact of Stranded Cost recovery on the effectiveness of
15 competition. As stated above, I believe there will be no impact on stranded cost
16 recovery if recovery is made through a non-bypassable wires charge paid by all
17 customers.

18 Pertaining to item No. 2), which refers to “The impact of Stranded Cost
19 recovery on customers of the Affected Utility who do not participate in the
20 competitive market,” if a wires charge is adopted, then customers who do not
21 participate in competition are subject to the same recovery of stranded costs as
22 customers who do participate. Therefore, the recovery of stranded costs via a
23 wire charge is equitable.

24 No. 3) refers to “the impact, if any on the Affected Utility’s ability to meet
25 debt obligations.” I believe there will be no significant impact on debt repayment
26 even if there is significantly less than 100 percent stranded cost recovery.

1 No. 4) states "The impact of Stranded Cost recovery on prices paid by
2 consumers who participate in the competitive market." The impact of stranded
3 cost recovery will add to the total price of electricity, but will not result in a
4 competitive disadvantage.

5 No. 6) "The degree to which the Affected Utility has mitigated or offset
6 Stranded Costs," would be taken into account in my proposed approach.

7 No. 7) "Appropriate treatment of negative costs" implies that a net system
8 approach is taken whereby negative stranded costs are netted against positive
9 stranded costs.

10 I also wish to clarify No. 9). I do not believe that "The ease of
11 determining the amount of stranded costs" should be a significant factor when
12 hundreds of millions of dollars are at stake. Even a sale price must be evaluated by
13 the Arizona Corporation Commission (ACC) on an administrative basis to
14 determine reasonableness with relation to projected market prices. I propose
15 deleting No. 9), as I do not think it is relevant to the Commission's determination
16 of mechanisms and charges relevant to stranded costs.

17 No. 10) mentions "The applicability of Stranded Cost to interruptible
18 customers." Stranded costs are highly relevant to interruptible customers since
19 most stranded costs are related to baseload plant and should be calculated on a
20 per- kWh basis for the energy used by interruptible customers.

21 No. 11), which states "The amount of electricity generated by renewable
22 generating resources owned by the Affected Utility," is only directly relevant if
23 these resources are priced above market. This depends on whether or not there is a

1 renewable generation requirement under restructuring in Arizona. Section R14-2-
2 1609 of the Rules refers to a solar portfolio standard, which may be referenced in
3 No. 11).

4 The critical element missing in Section I is related to the provision of
5 standard offer service. In pricing its standard offer service, the incumbent utility
6 should use the retail price of generation as the baseline. If the utility offers standard
7 offer service at rates below the retail price of generation, competition among
8 generation service providers will not occur. The use of the retail price of
9 generation as the baseline for setting the price for the Standard Offer Service
10 should not be just a "consideration," but a requirement on the part of the utility in
11 establishing its Standard Offer. The Commission should include this in
12 consideration of recovery mechanisms and stranded cost determinations by adding,
13 as a "consideration" No. 12).

14 12) The use of a retail price of generation as a baseline for
15 establishing the price of Standard Offer Service.
16

17 Q. DO YOU RECOMMEND ANY CHANGES TO SECTION J OF R14-2-1607
18 ON THE RECOVERY OF STRANDED COSTS BY AFFECTED UTILITIES?

19 A. I believe that Section J should be clarified. Section J states,

20 "Stranded costs may only be recovered from customer purchases
21 made in the competitive market using the provisions of this Article.
22 Any reduction in electricity purchases from an Affected Utility
23 resulting from self-generation, demand-side management, or other
24 demand reduction attributable to any cause other than the retail
25 access provisions of this article shall not be used to calculate or
26 recover any Stranded Cost from a consumer."

1
2 I agree with this basic position. Recovering stranded costs from a customer for
3 load reductions due to technological change implies the use of an exit fee and is
4 not appropriate. Exit fees are problematic for several reasons. First, the lump sum
5 payment (however it is determined) could create an insurmountable financial
6 barrier for some customers. Secondly, there is no regulatory precedent for
7 charging for stranded costs, or any costs, for power not purchased from the utility.
8 If a customer reduces its load, regulatory policy should not attempt to distinguish
9 among the various possible causes of such load reduction by imposing an exit fee if
10 the reduction is due to the increased self-generation of power, but not imposing
11 that fee if the load reduction is due to energy conservation effects, or shutting
12 down an assembly line. Therefore, Section J should be restated as,

13 "Stranded costs will be recovered from all customers continuing to
14 use the distribution system based on the amount of generation
15 purchased from any supplier. Any reduction in electricity purchased
16 from an Affected Utility resulting from self-generation, demand-
17 side management, or other demand reduction attributable to any
18 cause shall not be used as the basis to recover Stranded Costs from
19 a consumer."
20

21 Q. DO YOU RECOMMEND ANY CHANGES TO SECTIONS K AND L OF R14-
22 2-1607 ON THE RECOVERY OF STRANDED COSTS BY AFFECTED
23 UTILITIES?

24 A. I have no recommended changes for Section K. Regarding Section L, which states,
25 "The Commission may order regular revisions to estimates of the magnitude of
26 Stranded Cost," I agree that the ACC should revise stranded cost estimates, and
27 recommend this be achieved through a periodic true-up mechanism, as stated

1 previously. The amount of stranded cost recovery from ratepayers should be
2 calculated administratively and trued-up annually (or bi-annually) to account for
3 the actual market prices of generation. Please refer to the question above on the
4 true-up mechanism for further discussion of this issue.

5

6 Q. DO YOU RECOMMEND ANY CHANGES TO ANY SUB-SECTIONS OF
7 RULE R14-2-1606 WHICH ARE REQUIRED IN ORDER TO IMPLEMENT
8 THE STRANDED COST RELATED POLICY ISSUES THAT YOU HAVE
9 DISCUSSED ABOVE?

10 A. Yes, I recommend that No. 1 of Section B on Standard Offer Tariffs in Section
11 R14-2-1606 be changed. This section currently states,

12 1. By the date indicated in R14-2-1602, each Affected Utility
13 may file proposed tariffs to provide Standard Offer Bundled
14 Service and such rates shall not become effective until
15 approved by the Commission. If no such tariffs are filed, rates
16 and services in existence as of the date in R14-2-1602 shall
17 constitute the Standard Offer.

18
19 To freeze rates at their December 31, 1997 level does not benefit customers on the
20 Standard Offer, and may inhibit the process of competition. A price cap on the
21 generation rate is necessary during the transition to completely unregulated
22 generation markets in order to protect ratepayers from any adverse effects of the
23 unregulated generation market during this time period. The rate cap should be at
24 or below the level that rates would have been under continued regulation. The
25 Standard Offer should further provide customers with a rate reduction below the
26 rate cap. Therefore No. 1 of Section B should be reworded to say:

1 1. By July 1, 1998, each Affected Utility must file proposed
2 tariffs to provide Standard Offer Service and such rates shall
3 not become effective until approved by the Commission. The
4 Standard Offer rate should be set at a level below the level at
5 which rates were on December 31, 1997, and below the rate
6 cap which should be established by the ACC for the transition
7 period (January 1, 1999-January 1, 2003). The generation
8 component of the Standard Offer Service should be set by the
9 ACC at a market-based level for retail generation services.
10

11 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

12 A. Yes, it does.

RICHARD A. ROSEN

**Executive Vice-President
Senior Research Director
Tellus Institute
11 Arlington Street
Boston, MA 02116 USA
Tel. (617) 266-5400
Fax. (617) 266-8303
Email: rrosen@tellus.org**

Education

Ph.D.	Physics, Columbia University, 1974
M.A.	Physics, Columbia University, 1969
B.S.	Physics and Philosophy, M.I.T., 1966

Experience

1997-present	Manager of Electricity Group, Tellus Institute.
1993-1997	Director of Energy Group, Tellus Institute.
1991-present	Director of Planning, Tellus Institute.
1977-present	Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modelling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning.
1978-1980	Consultant to Brookhaven National Laboratory.
1979	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976-1978	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974-1976	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973	Instructor, Putney - Antioch Graduate School.

Testimony

Agency	Case or Docket No.	Date	Topic
New Jersey Office of Administrative Law	BPU E097070 456 OAL PUC 7311- 97 (Tellus 97- 203/A6)	Nov. 1997	Importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Atlantic City Electric)
New Jersey Office of Administrative Law	BPU EO9707 0459 OAL PUC- 7308-97 BPU E09707 0458 OAL PUC- 7307-97 (Tellus 97- 203/A3)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Jersey Central Power & Light dba GPU Energy)
New Jersey Office of Administrative Law	BPU E09707 0462 OAL PUC- 7347-97 BPU EO9707 0461 OAL PUC- 7348-97 (Tellus 97- 203/A1)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Public Service Electric & Gas Company)
Public Utility Commission of Texas	473-96-2285 and 16705 Tellus 97-046)	Sept. 1997	Competitive issues
Michigan Public Service Commission	U-11283 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test

Michigan Public Service Commission	U-11337 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test
New York Public Service Commission	96-E-0898 (Tellus 97-009)	May 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Rochester Gas and Electric Corp., and public policy recommendations on key issues related to market structure, market power, and the likelihood of RG&E's proposed retail access program actually leading to competition
New York Public Service Commission	96-E-0897 (Tellus 97-009)	April 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Consolidated Edison Company of New York, Inc., and public policy recommendations related to market structure and market power
New York Public Service Commission	96-E-0891 (Tellus 97-009)	February 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of New York State Electric and Gas Company, and public policy recommendations on key issues related to market structure and market power
Missouri Public Service Commission	EM-96-149 (Tellus 96-214)	Nov. 1996	Various issues related to market power
Federal Energy Regulatory Commission	EC96-10-000 (Tellus 96-050F)	Sept. 1996	Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization
Maryland Public Service Commission	8725 (Tellus 96-050)	July 1996	Review of the joint application of BGE and PEPSCO for approval of their proposed merger and reorganization

Illinois Commerce Commission	95-0551 (Tellus 95-302)	March 1996	Review of joint application of Central Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization
Vermont Public Service Board	5724 (Tellus 94-064)	July 1994	Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio
Illinois Commerce Commission	94-0065 (Tellus 94-112A)	June 1994	Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment
		July 1994	Rebuttal Testimony in above docket
Kansas Corporation Commission	180,056-U	February 1994	Oral Testimony (no written testimony) on establishment of IRP rules for electric and gas utilities
Public Utilities Commission of Hawaii	7257 (Tellus 93-144A3)	December 1993	Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning
Arkansas Public Service Commission	93-132-U (Tellus 93-148)	November 1993	Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River
		January 1994	Sur-Rebuttal Testimony in above docket
Public Utilities Commission of Georgia	4152-U (Tellus 93-100)	August 1993	Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company

Pennsylvania Public Utility Commission	A-110300 F. 051 (Tellus 92-026)	July 1993	Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation
Public Utilities Commission of Ohio	91-635-EL- FOR 92-312-EL- FOR 92-1172-EL- FOR (Tellus 92-165)	April 1993	Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report
Georgia Public Service Commission	4133-U, 4136-U (Tellus 92-078)	October 1992	Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995
Public Utilities Commission of Ohio	92-708-EL- FOR 92-1123-EL- FOR (Tellus 92-041A)	September 1992	Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process
Public Service Commission of the State of Georgia	4131-U, 4136-U (Tellus 91-266)	June 1992	Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO)
U.S. Bankruptcy Court - Manchester, NH	BK-91- 11336 Chapter 11	March 1992	Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc.
Public Utilities Commission of Ohio	91-410- EL-AIR (Tellus 91-082)	December 1991	Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the juris- diction of the Public Utilities Commission of Ohio (PUCO)

Public Utilities Commission of Ohio	92-418-EL-AIR (Tellus 91-091)	December 1991	Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Maine Public Utilities Commission	89-193, 89-194, 89-195 (ESRG 89-189B & 90-039)	August 1990	Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids.
New Hampshire Public Utilities Commission	DF 89-085 (ESRG 90-051)	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers
		September 1990	Supplemental Testimony in above docket.
Florida Public Service Commission	891345-EI (ESRG 90-017)	April 1990	Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit.
Michigan Public Service Commission	U-9458 (ESRG 89-158)	February 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	December 1989	Presentation of results of ESRG Study: <i>The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.</i>
		February 1990	Further Testimony in above Docket
		February 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	October 1989	Recommendations regarding the proper ratemaking treatment for PECO's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity

Federal Energy Regulatory Commission	ER88-630- 000 (ESRG 88-153)	April 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88- 128D)	February 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO
	(ESRG 88- 128E)	March 1989	Rebuttal Testimony
Michigan Public Service Commission	U-8871 (ESRG 88-32)	April 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	August 1988	Rebuttal Testimony
Maine Public Utilities Commission	87-268 (ESRG 30A)	April 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power
	87-268 (ESRG 87- 30A1)	August 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	February 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs
Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	November 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85- 35E)	December 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment

Pennsylvania Public Utility Commission	R-870651 (ESRG 87- 50D)	October 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.
Federal Energy Regulatory Commission	ER-86- 694-001	September 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission
Maine Public Utilities Commission	86-85	June 1987	Investigation of Reasonableness of Rates
		August 1987	Surrebuttal
Maryland Public Service Commission	7972	February 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company
Arizona Corporation Commission	U-1345- 85-367 (Tellus 86-42B)	February 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578	January 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	January 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378 (Tellus 85-083A)	September 1986	Economics of Duquesne Light Company's Share of Perry 1
		November 1986	Surrebuttal
Pennsylvania Public Utility Commission	R-850267 (Tellus 85-083B)	September 1986	Economics of Penn Power's Share of Perry 1
		November 1986	Surrebuttal

		March 1987	Supplemental
Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	April 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	February 1986	Power Supply Cost Recovery Plan for Consumers Power
Michigan Public Service Commission	U-8297	January 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	January 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of Business Regulation	85-2011-01 85-999-08	January 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern Utah
New York Public Service Commission	28252	October 1985	Shoreham - Rate Moderation
		January 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224 (Tellus 83-080)	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560- 000 (Tellus 85-019)	April 1985	Callaway Excess Capacity and a Review of Union Electric Planning
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	April 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas

Michigan Public Service Commission	U-8042	February 1985	Power Supply Cost Recovery Plan for Consumers Power Company
Michigan Public Service Commission	U-8020	January 1985	Power Supply Cost Recovery Plan for Detroit Edison Company
Massachusetts Department of Public Utilities	84-49, 84-50, 84-140, 627, 1656 & 1957	January 1985	Economics of Completing Seabrook 1 for Four Massachusetts Utilities
Michigan Public Service Commission	U-7830(M)	December 1984	Future Capacity Requirements of Consumers Power Company
New Hampshire Public Utilities Commission	84-200	November 1984	Investigation of Public Service Company of New Hampshire Financing Plan to Complete Construction of Seabrook 1
Michigan Public Service Commission	7830	October 1984	In the Matter of the Application of Consumers Power Company for Authority to Increase its Rates Applicable to the Sale of Electricity
Maine Public Utilities Commission	84-113	September 1984	Investigation of Seabrook Involvement by Maine Utilities
Missouri Public Service Commission	ER-84-168	August 1984	In the Matter of Union Electric Company of St. Louis, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company
Michigan Public Service Commission	U-7785	April 1984	In the Matter of the Application of Consumers Power Company for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for Calendar Year 1984
Ohio Power Siting Board	02-00022	February 1984	In the Matter of the Cleveland Electric Illuminating Company/Ohio Edison Company Amended Application to Construct and Operate a Transmission Facility Identified as the Perry-Hanna 345 kV Transmission Line

Michigan Public Service Commission	U-7775	February 1984	In the Matter of the Application of Detroit Edison Company to Implement a Power Supply Recovery Plan in its 1984 Electrical Rates
Maine Public Utilities Commission	81-276	July 1983	As to the Avoided Costs for Cogeneration and Small Power Production Facilities on the Maine Public Service Company System
South Carolina Public Service Commission	82-352-E	June 1983	Review of A.S. Beck Analyses Regarding the Economics of the Catawba Nuclear Station
North Carolina Utilities Commission	E-2, Sub 461	June 1983	Application by Carolina Power and Light Company for Increase in Electric Rates
Michigan Public Service Commission	U-7550	May 1983	Application of Detroit Edison Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Michigan Public Service Commission	U-7512	April 1983	Application of Consumers Power Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Pennsylvania Public Utilities Commission	R-822169	March 1983	Excess Capacity for Pennsylvania Power & Light Company
North Carolina Utilities Commission	E-100, Sub 47	February 1983	Power Plant Performance Standards and and Fuel Adjustment Clauses
Federal Energy Regulatory Commission	ER82-481 1982	December Options	Overview of Conservation and Generation
Kentucky Public Service Commission	83-14	December 1982	Review of the Kentucky-American Water Company Capacity Expansion Program
Maine Public Utilities Commission	81-276	December 1982	As to the Avoided Costs for Cogeneration and Small Power Producers
Maine Public Utilities Commission	81-114	November 1982	Maine Public Service Company Investigation of Power Supply Planning and Purchases

Maine Public Utilities Commission	82-174	October 1982	Capital Costs of the Seabrook Nuclear Units
Indiana Public Service Commission	36818	October 1982	An Economic Assessment of the Marble Hill Nuclear Station
New Hampshire Public Utilities Commission	DE81-312	October 1982	Investigation Into Supply and Demand of Electricity for Public Service Company of New Hampshire
Michigan Public Service Commission	U-6923	May 1982	Consumers Power Company Electricity Case
Alabama Public Service Commission	18337	January 1982	Long-Range Capacity Expansion Analysis
State of New York Energy Planning Board	SEMP II Hearings	November 1981	Conservation and Generation Planning
Pennsylvania Public Utility Commission	80100341	September 1981	Operating and Capital Costs: Limerick Nuclear Station; Surrebuttal
Maine Public Utilities Commission	MPUC 80- 189	April 1981	Electric Energy Costs: Seabrook Nuclear Power Plants; Surrebuttal
Pennsylvania Public Utility Commission	I-80100341	February 1981	Operating and Capital Costs: Limerick Nuclear Generating Station
Ohio Public Utilities Commission	80-141 EL-AIR	December 1980	CAPCO Construction Program; Generation Planning
Michigan Public Service Commission	U-6360	September 1980	Generation Expansion Planning: Consumers Power Company
Pennsylvania Public Utility Commission	I-79070315	August 1980	CAPCO Construction Schedule; Surrebuttal
Connecticut Power Facility Evaluation Council	F-80	June 1980	Renewable Resource Electric Generation in Connecticut
Pennsylvania Public Utility Commission	I-79070317	March 1980	CAPCO: Generation Planning and Reliability

Michigan Public Service Commission	U-5979	June 1979	Forecast Critique and Adjustments: Consumers Power Company
Massachusetts Dept. of Public Utilities	19494	August 1978	Long-range Electric Demand Forecast: Boston Edison Company
Pennsylvania Public Utility Commission	438	March 1978	Long-range Forecast of Electric Energy and Demand (Philadelphia Electric Company)

Tellus Research

November 1997	<i>Restructuring the Electric Industry in Delaware.</i> A Draft Report by the Delaware Public Service Commission Staff. PSC Docket No. 97-229. Tellus Study No. 96-099. Co-author. Final Draft Report.
February 1997	"Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," submitted to <i>Energy Journal</i> . Co-author.
January 1997	<i>Sustainable Electricity for New England: Developing Regulatory and Other Governmental Tools to Promote and Support Environmentally-Sustainable Technologies in the Context of Electric Industry Restructuring.</i> The R/EST Project. A report to the New England Governors' Conference, Inc. Tellus No. 95-310. Project manager.
October 1996	<i>Comments on FERC's CRT NOPR in Docket No. RM96-11-000.</i> Submitted to: The National Association of State Utility Consumer Advocates. Tellus Study No. 96-142. Principal investigator.
January 1996	<i>Achieving Efficiency and Equity in Nevada's Electric Industry - Comments Submitted by the Attorney General's Office of Advocate for Customers of Public Utilities on Issues Posed by the State Assembly in A.C.R. #49 Directing a Study of Competition in the Generation, Sale, and Transmission of Electricity.</i> Tellus Study No. 95-153A1. Co-author.
December 1995	<i>Promoting Environmental Quality in a Restructured Electric Industry.</i> A Report to: The National Association of Regulatory Utility Commissioners. Tellus Study No. 95-056. Co-author.
October 1995	<i>Power Pools and Least-Cost Compliance with the Clean Air Act.</i> A Report to: the Pew Charitable Trusts. Tellus Study No. 94-113. Principal investigator.

Richard Rosen

Tellus Institute

September 1995	<i>Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities.</i> Tellus Study No. 93-251. Principal investigator.
September 1995	Discussion Paper: An Overview of the Generic Issues Related to the Amendment to Illinois Senate Bill 1058. Submitted to the Illinois Consumer Utility Board. Tellus Study No. 95-210.
September 1995	Tellus' Initial Comments on CEEP's Discussion and Conclusions of its Electric Competition Investigation (PA PUC Docket No. I-940032). Submitted to: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-012. Co-author.
May 1995-Present	<i>Analysis of Economics of the Sherman Biomass Generating Unit.</i> Prepared for: Wheelabrator Environmental Systems, Inc. Tellus Study No. 95-154. Co-author.
March 1995	<i>Order on Application for Reconsideration, Formal Case No. 813, Order No. 10590.</i> Public Service Commission of the District of Columbia. Tellus No. 94-051.
January 1995	<i>Order on Application for Reconsideration, Formal Case No. 813, Order No. 10554.</i> Public Service Commission of the District of Columbia. Tellus No. 94-051.
January 1995	In the Matter of a Notice of Inquiry to Consider Section III of the Energy Policy Act of 1992 - Integrated Resource Planning and Energy Efficiency Investments in Power Generation and Supply for Electric Utilities. Docket No. 94-342-U. Prepared for: Arkansas Public Service Commission. Tellus No. 92-153A4. Co-author.
October 1994	<i>Competition and the Tennessee Valley Authority.</i> White paper prepared for TVA's Board of Directors. Tellus Study No. 94-096. Co-author. Draft.
May 1994- December 1995	Independent Advisors to the Tennessee Valley Authority's Board of Directors during the Utility's Development of its First Integrated Resource Plan. Tellus Study No. 94-096. Project Manager.
December 1994	<i>Report on Notice of Advanced Rulemaking Relating to Commission Review of Siting and Construction of Electric Transmission Lines.</i> Submitted to: Pennsylvania Office of Consumer Advocate. Docket No. L-00940091. Tellus Study No. 94-223. Co-author.
November 1994	"Comments in Response to Edison Electric Institute's Petition for Statement of Policy on the Ratemaking Treatment of the Costs Associated with SO ₂ Emissions Allowances." Docket No. PL95-1-000. Federal Energy Regulatory

Commission. Tellus Study No. 94-113. Co-author.

- September 1994 *Electric Transmission Pricing.* A report to: American Wind Energy Association. Tellus Study No. 94-39. Co-author.
- April 1994 *Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings.* Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300. Co-author.
- December 1993 *Aligning Rate Design Policies with Integrated Resource Planning.* A report to: National Association of Regulatory Utilities Commissioners. Tellus Study No. 92-047. Co-author.
- August 1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 35: Adoption of the Guidelines for Integrated Resource Planning by Electric Cooperatives. Tellus Study No. 93-053. Co-author.
- August 1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 39: PURPA Standards as Amended by the Energy Policy Act of 1992. Tellus Study No. 93-054. Co-author.
- July 1993 *IRP Concepts and Approaches.* Report to Hydro-Quebec and the Public Interest Groups and Associations. Tellus Study No. 92-155. Project Manager.
- June 1993 *Proposed Rules Governing Integrated Resource Planning for Electric and Natural Gas Utilities Regulated by the State of Kansas.* In collaboration with Kansas Corporation Commission Staff. Tellus Study No. 92-105. Project Manager.
- May 1993 *Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company Ltd.* Prepared for Consumers Gas Company, Ltd. Tellus No. 91-001. Project Co-manager. Not publicly available.
- January 1992 *Sales Forecasts and Price Changes for New Hampshire Electric Cooperative.* Prepared for: Members Committee of New Hampshire Electric Cooperative. Tellus Project No. 91-173. Principal investigator.
- September 1991 *America's Energy Choices: Investing in a Strong Economy and a Clean Environment.* In collaboration with the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, the Natural Resources Defense Council, and the Alliance to Save Energy. Tellus Study No. 90-067. Co-author.
- September 1990 *Environmental Impacts of Long Island's Energy Choices: The Environmental Benefits of Demand-Side Management.* Tellus No. 90-028A. Co-author.

Richard Rosen

Tellus Institute

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April 1990 *Comments on Pacific Power and Utah Power Resource and Market Planning Program.* On behalf of Committee of Consumer Services, Utah Department of Commerce. ESRG No. 90-050A. Author.

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July 1989 *Rhode Island's Options for Electric Generation.* A Policy Statement of the Energy Coordinating Council. ESRG No. 89-004. Co-author.

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April 1988 *An Evaluation of Central Maine Power Company's Proposed Purchase of Power from Hydro Quebec.* A Report to the Maine Public Utilities Commission Staff. ESRG Report No. 87-30. Principal Investigator.

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May 1986 *Midland Options Study - A Response.* A report to the Michigan Department of the Attorney General. ESRG Study No. 85-35. Principal Investigator.

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May 1984 *Power Planning in Kentucky: Assessing Issues and Choices. Project Summary Report to the Public Service Commission.* ESRG Study No. 83-51. Project manager.

April 1984	<i>Power Planning in Kentucky: Assessing Issues and Choices. Generation and Transmission System Planning.</i> ESRG Study No. 83-51/TR II. Project manager. Principal investigator.
April 1984	<i>Power Planning in Kentucky: Assessing Issues and Choices. Utility Financial Forecasts: Two Case Studies.</i> ESRG Study No. 83-51/TR IV. Project manager.
April 1984	<i>Draft Report: Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.</i> ESRG Study No. 83-81. Principal investigator.
January 1984	<i>Electric Rate Consequences of Retiring the Robinson 2 Nuclear Power Plant.</i> ESRG Study No. 83-10.
January 1984	<i>Power Planning in Kentucky: Assessing Issues and Choices. Conservation as a Planning Option.</i> ESRG Study No. 83-51/TR III. Project manager.
December 1983	<i>Power Planning in Kentucky: Assessing Issues and Choices. Long Range Forecasts for Kentucky and its Six Major Utilities.</i> ESRG Study No. 83-51/TR I. Project manager.
July 1983	<i>Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings.</i> ESRG Study No. 83-14/S. Co-author.
October 1982	<i>The Economics of Closing the Indian Point Nuclear Power Plants.</i> ESRG Study No. 82-40. Principal investigator.
October 1982	<i>Final Report of the Kentucky Public Service Commission.</i> ESRG Study No. 82-45. Co-author.
August 1982	<i>Nuclear Capacity Factors: The Effects of Aging and Salt Water Cooling. A Report on Research in Progress.</i> ESRG Study No. 82-81. Co-author.
August 1982	<i>The Impacts of Early Retirement of Nuclear Power Plants: The Case of Maine Yankee.</i> ESRG Study No. 82-91. Co-author.
April 1982	<i>A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company.</i> ESRG Study No. 81-61. Principal investigator.
January 1982	<i>Guidelines for Designing Rates for Sales to Qualifying Facilities Under Section 210 of the Public Utilities Regulatory Policies Act.</i> ESRG Study No. 81-32. Co-author.

- July 1981 *Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern System.* ESRG Study No. 80-63. Co-author.
- June 1981 *An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill.* A Report to: Robert M. Herzog, Director, New York City Energy Office and Allen G. Schwartz, Corporation Counsel for the City of New York. ESRG Study No. 81-21. Co-author.
- October 1980 *The ESRG Electrical Systems Generation Model: Incorporating Social Costs in Generation Planning.* ESRG Study No. 80-12. A Report to the U.S. Department of Energy. Co-author.
- September 1980 *Reducing New England's Oil Dependence Through Conservation and Alternative Energy.* ESRG Study No. 79-29. A Report to the U.S. General Accounting Office. Co-author.
- July 1980 *Preliminary Economic and Need Analysis of the Proposed Brumley Gap Pumped Storage Facility for the AEP System.* ESRG Study No. 80-08/P. Principal investigator.
- July 1980 *The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance.* ESRG Study No. 80-09. A Report to the Connecticut Power Facility Evaluation Council. Co-author.
- November 1979 *South Carolina Electric Demand Curtailment Planning.* A Report to the South Carolina Office of Energy Resources. Principal investigator.
- May 1979 *Demand Curtailment Planning: Methodology.* ESRG Study No. 78-18. Chapter submitted to Brookhaven National Laboratory and the Department of Energy for the Electric Demand Curtailment Planning Study. Principal investigator.
- May 1979 *Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model.* ESRG Study No. 79-06. A Report to the New England Conference of Public Utility Commissioners. Co-principal investigator.
- October 1978 *The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993.* ESRG Study No. 78-16. Co-author.
- November 1977 *Profile of Targets for the Energy Advisory Service to Industry.* ESRG Study No. 77-09. A Report to the New York State Energy Office. Co-Author.

- October 1977 *The Effect on Air and Water Emissions of Energy Conservation in Industry.*
ESRG Study No. 77-04. Co-author.
- July 1977 *The Effects on Air and Water Emissions of Energy Conservation in Industry.*
ESRG Study No. 77-04. Co-author.
- June 1977 *Toward an Energy Plan for New York.* ESRG Study No. 77-03. A Report to
the Legislative Commission on Energy Systems. Co-author.
- April 1977 *Assessing Demand, Alternative Operating Strategies, and Utility Economics in
the Service Territory of Orange and Rockland Utilities.* ESRG Report No.
77-01. Co-author.

Other Publications

- 1992 "Bill Indexing," chapter in: *Regulatory Incentives for Demand Side
Management*, edited by S. Nadel, et al. Published by ACEEE/NYSERDA.
With David Moskovitz.
- March 1978 *The Use of the Pulp and Paper Industry Process Model for R&D Decision
Making.* Brookhaven National Laboratory Report No. BNL 24134. Co-author.
- 1976 "A Non-Linear Model for the Linewidth, Intensity, and Coherence of
Astrophysical Masers," *Astrophysical Journal* vol. 190.

Papers and Presentations

- 1997 "How Do You Compute Stranded Costs?" A talk to ELCON. Washington, DC. October 30.
- 1997 "An Overview of Key Issues in Electric Industry Restructuring," presented to the Colorado Office of Consumer Counsel. June 26. Co-author.
- 1997 "Letting Retail Competition Succeed," presented at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.
- 1997 "A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," distributed at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.
- 1997 "A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Panelist.
- May 1997 "Market Power, Mergers, and Deregulation: A Critique of FERC's New Merger Guidelines," The National Regulatory Research Institute *Quarterly Bulletin*.
- April 1997 "A Whitepaper On Stranded Costs and Market Structures in the U.S. Electricity Industry," prepared for: The American Association of Retired Persons. Tellus No. 97-009. Draft.
- 1997 "A Point/Counterpoint Analysis of Major Restructuring Issues." Co-author.
- June 1996 "Leveraging" - The Key to the Exercise of Market Power in a Poolco. NARUC and NASUCA Summer Meetings. Co-author.
- September 1995 "The Status of Regulatory Policy Affecting the Restructuring of the Electric Utilities Industry." Presentation to: Wheelabrator Technologies, Inc.
- August 1995 Presentation to Maine Public Service Company on Behalf of Wheelabrator Sherman to explain Tellus' Calculation of Estimates of Total Avoided Costs for Wheelabrator Sherman Power through 2015. Co-author.
- November 1994 "Nine Fallacies in Computing Avoided Costs." Distributed at: The Annual NARUC/NASUCA Conference, Reno, NV. Co-author.

September 1994	"Apples and Oranges: Using Multi-Attribute Analysis in a Collaborative Process to Address Value Conflicts in Electric Facility Siting." Presented at: Ninth National Association of Regulatory Utility Commissioners (NARUC) Biennial Regulatory Information Conference, Columbus, Ohio, September 8. Co-author.
1993	"How Should Electric Utilities Allocate Their Free EPA-Granted Allowances Among Retail and Wholesale Customers? An Unresolved Issue of Clean Air Act Compliance. Prepared for distribution at: The NARUC/NASUCA 1993 Annual Meetings, New York, NY. November 14. Co-author.
February 1993	"Integrated Resource Planning and Clean Air Act Compliance: Elements of Consistency." Prepared for Distribution at: The NARUC Energy Conservation Committee 1993 Winter Meeting, Washington, DC. Co-author.
February 1991	"The Clean Air Act Amendments of 1990 and Utility Least Cost Planning: Issues for State Regulators," for distribution at the NARUC Conservation Committee, 1991 Winter Meeting, Washington, D.C. Co-author.
February 1991	"Sustainable Development and the Future of Electric Utilities," for the Energy Conservation Coalition Electric Utility Industry Vision Paper Project, Washington, DC.
September 1989	"Six Fallacies in Computing Avoided Costs," delivered at the NARUC Least Cost Planning Conference, Charleston, S.C.
October 1988	"Ratemaking and Conservation: The Tune Should Fit the Dance," distributed at the NARUC Committee on Energy Conservation Meeting, San Francisco. October 30.
September 1987	"Electric Utility System Reliability and Reserves" (ESRG Paper). Co-author.
September 1986	"Risk Sharing and the 'Used and Useful' Criterion in Utility Ratemaking" (ESRG Paper). Co-author.
September 1986	"Risk Sharing, Excess Capacity, and the 'Used and Useful' Criterion." Presented to the Fifth Biennial Regulatory Information Conference sponsored by the National Regulatory Research Institute in Columbus, Ohio.
July 24-28 1978	"Energy Use Modelling of the Iron and Steel Industry," Summer Computer Simulation Conference.
Nov. 12 1977	"Energy Conservation in Industry," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Related Professional Activities

Elected to Three-Year Term as a member of the Research Advisory Committee of The National Regulatory Research Institute, October 1, 1988 - September 30, 1991. Term extended through June 1992.

Invited Speaker

March 1997	"Evaluating the Competitive Effect of Electric and Gas Utility Mergers Under Retail Competition." Panel - "Merger and Acquisitions: Implications of the Convergence of Electric and Gas Industries," <i>Current Issues Challenging the Regulatory Process</i> , Center for Public Utilities, New Mexico State University, Santa Fe, NM. March 11.
November 1996	"NASUCA's Filing on the CRT NOPR at FERC," NASUCA Annual Conference.
June 1996	"Independent System Operators," NASUCA meeting, Chicago, IL.
November 1995	"Preserving Environmental Quality Under Electric Restructuring," NARUC Energy Conservation Committee meeting, New Orleans, LA.
November 1994	"Electricity Transmission Pricing," presented at NARUC Committee on Energy Conservation, Annual Meeting, Reno, NV. Co-author.
September 1994	Sixth Natural Gas Industry Forum, Quebec City. September 25-28.
June 1993	The National Energy Summit, in conjunction with the Multi-Media Energy Education Project of the Jefferson Energy Foundation - "Balancing Energy-Environment-Economy (E ³)", Washington, DC. Panelist.
September 1992	"Natural Gas Planning: An IRP Case Study." Presented at: The NARUC Conference on Integrated Resource Planning, Burlington, Vermont, September 13-16, 1992. Co-author.
September 1992	Fourth Natural Gas Industry Forum, Montreal.
March 1992	American Gas Association Long Range Forecasting for Integrated Resource Planning Seminar - "How Externalities and Supply Costs Affect IRP".
December 1991	Edison Electric Institute -- Strategic Planning Committee - "Incorporating Environmental Externalities into Integrated Resource Planning".

Richard Rosen

Tellus Institute

November 1990 NARUC Energy Conservation Committee Meeting, Orlando, Florida - "Rate Impacts of Demand-Side Management Programs".

November 1990 NARUC and NASUCA Joint Annual Meeting, Orlando, Florida - "Environmental Externalities and Integrated Resource Planning".

Awards and Honors

1968-1974 Faculty Fellowship, Physics Department Columbia University.

1966-1970 New York State Regents Fellowship.

1967-1968 Adam Leroy Jones Fellow in Philosophy, Columbia University.

12/97

Summary of Stranded Costs Estimates

Net Present Value of Stranded Costs (1996-2010) (million 1998\$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	836	1198	42
High Market Price	411	1051	-440
Low Market Price	1211	1345	526

*Note: Stranded Costs for APS accounts for generation-related assets not in rates (\$110.3 million).

Net Present Value of Stranded Costs (1998-2012) (million 1998\$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	102	779	-834
High Market Price	-417	599	-1433
Low Market Price	559	959	-233

*Note: Stranded Costs for APS accounts for generation-related assets not in rates (\$110.3 million).

Net Present Value of Stranded Costs (1998-2020) (million 1998\$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	-838	513	-3009
High Market Price	-1578	257	-3927
Low Market Price	-186	770	-2090

*Note: Stranded Costs for APS accounts for generation-related assets not in rates (\$110.3 million).

Cost Components of a Retail Generation Services Adder ¹					
(mills per kWh)					
Arizona Public Service Company (APS) & Tucson Electric Power Company (TEP)					
Sources	Cost Component	Small Customers ²		Large Customers	
		- low case -	- high case -	- low case -	- high case -
1	Generation-related customer services	1.1	2.2	0.5	1.0
2	Other ancillary services not in current A&G	0.0	1.0	0.0	1.0
3	Generation-related A&G	5.0	5.0	5.0	5.0
4	<u>Marketing and advertising</u>	<u>1.1</u>	<u>2.2</u>	<u>0.5</u>	<u>1.0</u>
5	Subtotal	7.2	10.4	6.0	8.0
6	Profit	0.7	1.0	0.3	0.4
7	<u>Income tax</u>	<u>0.3</u>	<u>0.4</u>	<u>0.1</u>	<u>0.1</u>
8	Total	8.2	11.8	6.4	8.5

Weighted Average Retail Generation Services Adder Across Customer Classes					
APS & TEP- FERC Form 1 Data					
1996 Sales		Small Customers		Large Customers	
Residential Sales (MWH)		10,057,722		0	
Commercial Sales (MWH)		9,540,588		0	
Industrial Sales (MWH)		0		6,406,035	
Total Sales to Ultimate Customers (MWH)		19,598,310		6,406,035	
		- low case -	- high case -	- low case -	- high case -
Weighted Average Adder		7.7	11.0	7.7	11.0

Footnotes:

- 1 These retail adders are not intended to be estimates of appropriate "generation credits" for the purpose of stimulating competition in a pilot program.
- 2 Assumes a consumption of 917 kWh per month, average over APS and TEP small customers.

Sources

- 1 Billing and collection services, customer inquiries, etc.
- 2 Refer to Exhibit___(RAR-2) for a listing of these ancillary services.
- 3 APS: actual cost embedded in its average retail rate.
- 4 N.H. PUC set 3.7 mills per kWh in the N.H. pilots, based on expenditures of \$44 per small customer (500 kWh per month) over two years.
- 5 Subtotal of lines 1-4
- 6 Profit = 10% of retail adder
- 7 Income tax = 35% of profit
- 8 Total of lines 5-7

**Table 3b: Projecting Future Costs for
Arizona Public Service Company**
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	1.63	1.63	18,428	299.9
1997	1.37	1.37	18,753	256.0
1998	1.08	1.08	19,255	208.6
1999	0.78	0.78	19,523	152.1
2000	0.45	0.45	19,979	90.3
2001	0.32	0.32	19,968	63.3
2002	0.18	0.18	20,269	36.2
2003	0.04	0.04	20,911	7.5
2004	(0.11)	(0.11)	21,517	(23.9)
2005	(0.21)	(0.21)	22,110	(46.9)
2006	(0.32)	(0.32)	22,563	(71.5)
2007	(0.43)	(0.43)	23,024	(98.1)
2008	(0.54)	(0.54)	23,495	(126.7)
2009	(0.66)	(0.66)	23,975	(157.5)
2010	(0.78)	(0.78)	24,466	(190.6)
2011	(0.91)	(0.91)	24,966	(226.1)
2012	(1.04)	(1.04)	25,476	(264.2)
2013	(1.17)	(1.17)	25,997	(305.1)
2014	(1.31)	(1.31)	26,529	(348.8)
2015	(1.46)	(1.46)	27,072	(395.7)
2016	(1.61)	(1.61)	27,625	(445.8)
2017	(1.77)	(1.77)	28,190	(499.4)
2018	(1.93)	(1.93)	28,767	(556.6)
2019	(2.10)	(2.10)	29,355	(617.7)
2020	(2.28)	(2.28)	29,955	(682.9)

Net Present Value of Stranded Costs (1996-2010): \$726.0

Generation-Related Assets Not in Rates: \$ 110.3

Total NPV of Stranded Costs (1996-2010) (1998\$): \$836.3

Net Present Value of Stranded Costs (1998-2012): (\$8.1)

Generation-Related Assets Not in Rates: \$ 110.3

Total NPV of Stranded Costs (1998-2012) (1998\$): \$102.2

Net Present Value of Stranded Costs (1998-2020): (\$947.9)

Generation-Related Assets Not in Rates: \$ 110.3

Total NPV of Stranded Costs (1998-2020) (1998\$): (\$837.6)

Assumed utility nominal discount rate 7.75%

System generation, excluding purchased power. Assumed escalation rate:

2.0%

Table 3a: Projections of Stranded Costs¹

Arizona Public Service Company

Scenario: Base year wholesale price based on average price of purchased power

Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year,

CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

O&M Costs

3.0%

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.66	5.02	0.00
1998	3.94	5.02	0.00
1999	4.24	5.02	0.00
2000	4.57	5.02	0.00
2001	4.70	5.02	0.00
2002	4.84	5.02	0.00
2003	4.99	5.02	0.00
2004	5.13	5.02	0.00
2005	5.28	5.07	0.00
2006	5.44	5.12	0.00
2007	5.60	5.17	0.00
2008	5.77	5.23	0.00
2009	5.93	5.28	0.00
2010	6.11	5.33	0.00
2011	6.29	5.38	0.00
2012	6.48	5.44	0.00
2013	6.67	5.49	0.00
2014	6.86	5.55	0.00
2015	7.06	5.60	0.00
2016	7.27	5.66	0.00
2017	7.49	5.72	0.00
2018	7.71	5.77	0.00
2019	7.93	5.83	0.00
2020	8.17	5.89	0.00

¹ All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Arizona Public Service Company
 (thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	\$508,476	\$508,476			
O&M Minus Fuel	\$416,344	\$297,256			
Fuel	\$211,220	\$211,220			
Transmission	\$14,067		\$14,067		
Distribution	\$50,207			\$50,207	
Customer/Sales	<u>\$54,814</u>				<u>\$54,814</u>
Subtotal	\$627,564	\$508,476	\$14,067	\$50,207	\$54,814
A&G ¹	<u>\$133,222</u>	\$ 95,116	\$ 4,501	\$ 16,065	\$ 17,539
Total	\$760,786	\$603,592	\$18,568	\$66,272	\$72,353
Plant Related Costs:					
Depreciation and Amort.	\$237,555	\$130,281	\$29,423	\$77,852	\$0
Net Interest	\$1,077	\$551	\$126	\$401	\$0
Net Income	\$364,223	\$186,122	\$42,446	\$135,656	\$0
Income Taxes ²	\$178,514	\$91,222	\$20,804	\$66,488	\$0
Other Taxes ³	\$68,023	\$34,761	\$7,927	\$25,335	\$0
Residual ⁴	<u>\$55,014</u>	<u>\$28,113</u>	<u>\$6,411</u>	<u>\$20,490</u>	<u>\$0</u>
Total	\$904,406	\$471,049	\$107,136	\$326,221	\$0
Total Operating Revenues⁵	\$1,665,192	\$1,074,641	\$125,704	\$392,493	\$72,353
less Wholesale Revenues	<u>(\$133,416)</u>	<u>(\$119,445)</u>	<u>(\$13,972)</u>	<u>\$0</u>	<u>\$0</u>
Total Retail Revenues	\$1,531,775	\$955,196	\$111,732	\$392,493	\$72,353
Total Retail Sales (MWH)	19,020,696				
Average Retail Rate (cents/kWh)	8.05	5.02	0.59	2.06	0.38

Footnotes:

¹ A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 71.4%, 3.4%, 12.1%, and 13.2%.

² Income Taxes include Federal Income Taxes, Other Income Taxes, Provision for Deferred Income Taxes (incl. credits).

³ Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

⁴ Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

⁵ Total Operating Revenues do not include revenues collected from state sales taxes.

**Table 1: Market Price Calculation for
Arizona Public Service Company**
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

<u>Combined Cycle:</u>	<u>Total Costs:</u>	<u>1996 Real Levelized Costs</u>
Capital Costs	383.0 \$/kW	0.84 ¢/kWh
Fixed O&M	11.7 \$/kW-yr	0.24 ¢/kWh
Variable O&M	0.20 mills/kWh	0.02 ¢/kWh
Fuel	1.97 ¢/kWh	1.72 ¢/kWh
Sum of Levelized Costs:		2.82 ¢/kWh
Levelized Capacity Costs:		53.4 \$/kW-yr

<u>Combustion Turbine:</u>	<u>Total Costs:</u>	<u>1996 Real Levelized Costs</u>
Capital Costs	275.0 \$/kW	7.04 ¢/kWh
Fixed O&M	9.4 \$/kW-yr	2.21 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.16 ¢/kWh
Sum of Levelized Costs:		12.42 ¢/kWh
Levelized Capacity Costs:		39.3 \$/kW-yr

Capacity Factor Crossover for CC/CT	11%
Percent of CC energy in Market Price	98.1%
Percent of CT energy in Market Price	1.9%
Average Price of CC/CT mix	3.00 ¢/kWh

T&D Line Loss Adjustment	7%	0.21 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh

Adjusted Retail Market Price based on CC/CT mix	4.08 ¢/kWh
--	-------------------

Year Excess Capacity Ends	2000
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(2) Using Capacity Charge and Energy Charge:

Capacity Charge (\$/kW-yr):	NA	
Energy Charge (¢/kWh):	NA	
Average Market Price for Electricity:		none ¢/kWh

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		2.36 ¢/kWh
T&D Line Loss Adjustment	7%	0.16 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
User-Input Retail Market Price for Electricity		3.39 ¢/kWh

Table 4
Assumptions Used in Estimating Stranded Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996\$/MMBtu):		User-input	
1996	\$3.03	2004	\$2.53
1997	\$2.11	2005	\$2.72
1998	\$2.27	2006	\$2.73
1999	\$2.32	2007	\$2.73
2000	\$2.36	2008	\$2.73
2001	\$2.39	2009	\$2.71
2002	\$2.48	2010	\$2.71
2003	\$2.59	2011	\$2.72
		2012	\$2.75
		2013	\$2.71
		2014	\$2.73
		2015	\$2.75
		2016	\$2.80
		2017	\$2.85
		2018	\$2.90
		2019	\$2.95
		2020	\$3.00

Source: Exhibit_(RAR-6)

Combined Cycle:	
Capital Cost	383.0 1996\$/kW
Fixed O&M	11.7 1996\$/kW/yr
Var O&M	0.200 1996mills/kW
Heat Rate	6,500 Btu/kWh

Schnitzer, in Docket No. 16705, Texas Direct Testimony and EIA Annual Energy Outlook 1997

Combustion Turbine:	
Capital Cost	275.0 1996\$/kW
Fixed O&M	9.4 1996\$/kW/yr
Var O&M	0.100 1996mills/kW
Heat Rate	11,900 Btu/kWh

Tellus Institute, Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	54%
Max. Annual Load (MW)	4616
Min. Monthly Peak (MW)	2484
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	2023
Max. Load + Reserve Margin (MW)	5308
Cut-off point:	11.0%
Load at above Cut-off (MW)	4331
Total Energy under Load Curve (MWh)	21,865,083
Energy Supplied by CTs (MWh)	415,437
Energy Supplied by CCs (MWh)	21,449,646
Percentage of Energy Supplied by CTs	1.9%
Percentage of Energy Supplied by CCs	98.1%

Average Wholesale Market Price of Electricity Based on CC/CT Method	30.04 \$/MWh
T&D Line Loss Adjustment	0.21 c/kWh
Order 888 Ancillary Services	0.10 c/kWh
Retailing A&G Adjustment	0.50 c/kWh
Other Retailing Costs Adjstmt	0.27 c/kWh

Month-1996	Total Monthly Energy (MWh)	Monthly Non- Req. Sales for Resale & Losses (MWh)		Net Energy (MWh)	Monthly Peak (MW)
Jan	1,755,196	121,658		1,633,538	3,134
Feb	1,538,583	93,484		1,445,099	3,027
Mar	1,578,178	81,408		1,496,770	2,703
Apr	1,606,380	70,048		1,536,332	3,223
May	1,888,666	52,951		1,835,715	3,576
Jun	2,176,835	72,505		2,104,330	4,113
Jul	2,546,161	61,708		2,484,453	4,616
Aug	2,492,746	32,371		2,460,375	4,491
Sep	2,070,813	150,700		1,920,113	3,953
Oct	2,062,028	284,609		1,777,419	3,662
Nov	1,901,166	424,258		1,476,908	2,484
Dec	2,147,940	453,909		1,694,031	3,354
TOTAL	23,764,692	1,899,609		21,865,083	4,616

Utility FERC Form 1 Data

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	\$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	3.39 c/kWh	

CC-CT Market Price Worksheet for:

Arizona Public Service Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user.

Month	Total Monthly Energy (MWh)	Monthly Non- Requirements Sales for Resale & Associated Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
	USER-INPUT	USER-INPUT		USER-INPUT			
Jan	1,755,196	121,658	1,633,538	3,134			
Feb	1,538,583	93,484	1,445,099	3,027			
Mar	1,578,178	81,408	1,496,770	2,703			
Apr	1,606,380	70,048	1,536,332	3,223			
May	1,888,666	52,951	1,835,715	3,576			
Jun	2,176,835	72,505	2,104,330	4,113			
Jul	2,546,161	61,708	2,484,453	4,616			
Aug	2,492,746	32,371	2,460,375	4,491			
Sep	2,070,813	150,700	1,920,113	3,953			
Oct	2,062,028	284,609	1,777,419	3,662			
Nov	1,901,166	424,258	1,476,908	2,484	2484	81%	2,023
Dec	2,147,940	453,909	1,694,031	3,354			
TOTAL	23,764,692	1,899,609	21,865,083	4,616	2,484	0.81	2,023

LOAD FACTOR

54%

Max. Annual Load (MW)

4,616

Min. Monthly Peak (MW)

2,484

Load Factor for Min. Monthly Load

0.81

Effective Min. Annual Load

2,023

Max. Load + Reserve Margin (MW)

5,308

Cut-off point:

11%

Load at above Cut-off (MW)

4,331

ratio between total energy under load curve and total monthly energy	0.92
--	------

Total Energy under Load Curve (MWh)

21,865,083

Energy Supplied by CTs (MWh)

415,437

Energy Supplied by CCs (MWh)

21,449,646

check

0

Ratio of energy supplied by CTs

1.9%

Ratio of energy supplied by CCs

98.1%

\$ 28.21 MWh

CC

Capital Cost	41.67	\$/kW times	4,331	MW	equals	180,465,659	dollars
Fixed O&M	11.70	\$/kW times	4,331	MW	equals	50,670,217	dollars
Var O&M	0.20	mills/kWh times	21,449,646	MWh	equals	4,289,929	dollars
Fuel	1.72	cents/kWh times	21,449,646	MWh	equals	369,748,232	dollars

CT

Capital Cost	29.92	\$/kW times	978	MW	equals	29,250,158	dollars
Fixed O&M	9.40	\$/kW times	978	MW	equals	9,189,555	dollars
Var O&M	0.10	mills/kWh times	415,437	MWh	equals	41,544	dollars
Fuel	3.16	cents/kWh times	415,437	MWh	equals	13,110,652	dollars

\$ 124.19 MWh

TOTAL

656,765,946 dollars

Tot Energy
in real LDC

21,865,083 MWh

OUTPUT

Average Market Price of Electricity - 1996

30.04	\$/MWh
3.00	c/kWh

**Table 3b: Projecting Future Costs for
Arizona Public Service Company**

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.¹ (GWh)	Stranded Costs (\$ million)
1996	1.63	1.63	18,428	299.9
1997	1.32	1.32	18,753	247.1
1998	0.98	0.98	19,255	188.6
1999	0.61	0.61	19,523	119.2
2000	0.21	0.21	19,979	41.5
2001	0.07	0.07	19,968	13.2
2002	(0.08)	(0.08)	20,269	(16.2)
2003	(0.23)	(0.23)	20,911	(48.2)
2004	(0.39)	(0.39)	21,517	(82.9)
2005	(0.49)	(0.49)	22,110	(109.3)
2006	(0.61)	(0.61)	22,563	(137.1)
2007	(0.73)	(0.73)	23,024	(166.9)
2008	(0.85)	(0.85)	23,495	(199.0)
2009	(0.97)	(0.97)	23,975	(233.5)
2010	(1.11)	(1.11)	24,466	(270.4)
2011	(1.24)	(1.24)	24,966	(309.9)
2012	(1.38)	(1.38)	25,476	(352.3)
2013	(1.53)	(1.53)	25,997	(397.6)
2014	(1.68)	(1.68)	26,529	(446.0)
2015	(1.84)	(1.84)	27,072	(497.8)
2016	(2.00)	(2.00)	27,625	(553.1)
2017	(2.17)	(2.17)	28,190	(612.1)
2018	(2.35)	(2.35)	28,767	(675.0)
2019	(2.53)	(2.53)	29,355	(742.1)
2020	(2.72)	(2.72)	29,955	(813.6)

Net Present Value of Stranded Costs (1996-2010): **\$300.3**

Generation-Related Assets Not in Rates: \$ **110.3**

Total NPV of Stranded Costs (1996-2010) (1998\$): **\$410.6**

Net Present Value of Stranded Costs (1998-2012): **(\$527.1)**

Generation-Related Assets Not in Rates: \$ **110.3**

Total NPV of Stranded Costs (1998-2012) (1998\$): **(\$416.7)**

Net Present Value of Stranded Costs (1998-2020): **(\$1,688.4)**

Generation-Related Assets Not in Rates: \$ **110.3**

Total NPV of Stranded Costs (1998-2020) (1998\$): **(\$1,578.0)**

Assumed utility nominal discount rate **7.75%**

System generation, excluding purchased power. Assumed escalation rate:

2.0%

Table 3a: Projections of Stranded Costs¹
Arizona Public Service Company

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year,
 CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

O&M Costs

3.0%

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.70	5.02	0.00
1998	4.04	5.02	0.00
1999	4.41	5.02	0.00
2000	4.81	5.02	0.00
2001	4.96	5.02	0.00
2002	5.10	5.02	0.00
2003	5.25	5.02	0.00
2004	5.41	5.02	0.00
2005	5.57	5.07	0.00
2006	5.73	5.12	0.00
2007	5.90	5.17	0.00
2008	6.07	5.23	0.00
2009	6.25	5.28	0.00
2010	6.44	5.33	0.00
2011	6.63	5.38	0.00
2012	6.82	5.44	0.00
2013	7.02	5.49	0.00
2014	7.23	5.55	0.00
2015	7.44	5.60	0.00
2016	7.66	5.66	0.00
2017	7.89	5.72	0.00
2018	8.12	5.77	0.00
2019	8.36	5.83	0.00
2020	8.60	5.89	0.00

¹ All costs are in nominal dollars.

**Table 3b: Projecting Future Costs for
Arizona Public Service Company**

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.¹ (GWh)	Stranded Costs (\$ million)
1996	1.63	1.63	18,428	299.9
1997	1.41	1.41	18,753	264.2
1998	1.18	1.18	19,255	226.6
1999	0.93	0.93	19,523	181.4
2000	0.67	0.67	19,979	133.1
2001	0.54	0.54	19,968	107.4
2002	0.41	0.41	20,269	82.3
2003	0.27	0.27	20,911	56.4
2004	0.13	0.13	21,517	27.9
2005	0.04	0.04	22,110	7.9
2006	(0.06)	(0.06)	22,563	(13.9)
2007	(0.16)	(0.16)	23,024	(37.6)
2008	(0.27)	(0.27)	23,495	(63.1)
2009	(0.38)	(0.38)	23,975	(90.7)
2010	(0.49)	(0.49)	24,466	(120.4)
2011	(0.61)	(0.61)	24,966	(152.4)
2012	(0.73)	(0.73)	25,476	(186.8)
2013	(0.86)	(0.86)	25,997	(223.8)
2014	(0.99)	(0.99)	26,529	(263.4)
2015	(1.13)	(1.13)	27,072	(305.9)
2016	(1.27)	(1.27)	27,625	(351.5)
2017	(1.42)	(1.42)	28,190	(400.3)
2018	(1.57)	(1.57)	28,767	(452.6)
2019	(1.73)	(1.73)	29,355	(508.4)
2020	(1.90)	(1.90)	29,955	(568.1)

Net Present Value of Stranded Costs (1996-2010): **\$1,101.0**

Generation-Related Assets Not in Rates: \$ 110.3

Total NPV of Stranded Costs (1996-2010) (1998\$): **\$1,211.3**

Net Present Value of Stranded Costs (1998-2012): **\$448.6**

Generation-Related Assets Not in Rates: \$ 110.3

Total NPV of Stranded Costs (1998-2012) (1998\$): **\$558.9**

Net Present Value of Stranded Costs (1998-2020): **(\$296.6)**

Generation-Related Assets Not in Rates: \$ 110.3

Total NPV of Stranded Costs (1998-2020) (1998\$): **(\$186.3)**

Assumed utility nominal discount rate **7.75%**

System generation, excluding purchased power. Assumed escalation rate:

2.0%

Table 3a: Projections of Stranded Costs¹

Arizona Public Service Company

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year,

CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

O&M Costs

3.0%

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.61	5.02	0.00
1998	3.85	5.02	0.00
1999	4.09	5.02	0.00
2000	4.36	5.02	0.00
2001	4.48	5.02	0.00
2002	4.62	5.02	0.00
2003	4.75	5.02	0.00
2004	4.89	5.02	0.00
2005	5.04	5.07	0.00
2006	5.18	5.12	0.00
2007	5.34	5.17	0.00
2008	5.49	5.23	0.00
2009	5.66	5.28	0.00
2010	5.82	5.33	0.00
2011	5.99	5.38	0.00
2012	6.17	5.44	0.00
2013	6.35	5.49	0.00
2014	6.54	5.55	0.00
2015	6.73	5.60	0.00
2016	6.93	5.66	0.00
2017	7.14	5.72	0.00
2018	7.35	5.77	0.00
2019	7.56	5.83	0.00
2020	7.78	5.89	0.00

¹ All costs are in nominal dollars.

**Table 3b: Projecting Future Costs for
Salt River Project Agricultural Improvement & Power District**
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	1.24	1.24	18,856	233.4
1997	1.02	1.02	19,627	200.3
1998	0.79	0.79	20,430	161.4
1999	0.55	0.55	21,266	116.0
2000	0.29	0.29	22,135	63.4
2001	0.15	0.15	23,041	34.9
2002	0.01	0.01	23,983	2.9
2003	(0.13)	(0.13)	24,964	(32.7)
2004	(0.28)	(0.28)	25,985	(72.4)
2005	(0.43)	(0.43)	27,048	(116.4)
2006	(0.59)	(0.59)	28,154	(165.2)
2007	(0.75)	(0.75)	29,305	(219.2)
2008	(0.91)	(0.91)	30,504	(278.8)
2009	(1.08)	(1.08)	31,752	(344.4)
2010	(1.26)	(1.26)	33,050	(416.6)
2011	(1.44)	(1.44)	34,402	(495.9)
2012	(1.63)	(1.63)	35,809	(582.9)
2013	(1.82)	(1.82)	37,274	(678.3)
2014	(2.02)	(2.02)	38,798	(782.7)
2015	(2.22)	(2.22)	40,385	(896.8)
2016	(2.43)	(2.43)	42,037	(1,021.6)
2017	(2.65)	(2.65)	43,756	(1,157.7)
2018	(2.87)	(2.87)	45,546	(1,306.2)
2019	(3.10)	(3.10)	47,409	(1,468.1)
2020	(3.33)	(3.33)	49,348	(1,644.3)

Net Present Value of Stranded Costs (1996-2010) (1998\$): \$42.0

Net Present Value of Stranded Costs (1998-2012) (1998\$): (\$833.7)

Net Present Value of Stranded Costs (1998-2020) (1998\$): (\$3,009.1)

PV of Generation-Related Assets Not in Rates: \$0

Total Net Present Value of Stranded Costs (1998-2020) (1998\$): (\$3,009.1)

Assumed utility nominal discount rate 7.75%

System generation, excluding purchased power. Assumed escalation rate: 4.1%

Table 3a: Projections of Stranded Costs¹
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year,
 CC/CT Mix Method in Year Excess Capacity Ends
 See Table 4: Scenario Assumptions

Escalation Rates:

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.61	4.85	0.00
1997	3.83	4.85	0.00
1998	4.06	4.85	0.00
1999	4.30	4.85	0.00
2000	4.56	4.85	0.00
2001	4.70	4.85	0.00
2002	4.84	4.85	0.00
2003	4.98	4.85	0.00
2004	5.13	4.85	0.00
2005	5.28	4.85	0.00
2006	5.44	4.85	0.00
2007	5.60	4.85	0.00
2008	5.76	4.85	0.00
2009	5.93	4.85	0.00
2010	6.11	4.85	0.00
2011	6.29	4.85	0.00
2012	6.48	4.85	0.00
2013	6.67	4.85	0.00
2014	6.87	4.85	0.00
2015	7.07	4.85	0.00
2016	7.28	4.85	0.00
2017	7.49	4.85	0.00
2018	7.72	4.85	0.00
2019	7.95	4.85	0.00
2020	8.18	4.85	0.00

¹ All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Salt River Project Agricultural Improvement & Power District
 (thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	\$642,208	\$642,208			
O&M Minus Fuel	\$430,824	\$329,164			
Fuel	\$313,044	\$313,044			
Transmission	\$14,836		\$14,836		
Distribution	\$47,360			\$47,360	
<u>Customer/Sales</u>	<u>\$39,464</u>				<u>\$39,464</u>
Subtotal	\$743,868	\$642,208	\$14,836	\$47,360	\$39,464
<u>A&G¹</u>	<u>\$123,651</u>	<u>\$94,474</u>	<u>\$4,258</u>	<u>\$13,593</u>	<u>\$11,326</u>
Total	\$867,519	\$736,682	\$19,094	\$60,953	\$50,790
Plant Related Costs:					
Depreciation and Amort.	\$232,486	\$145,859	\$28,909	\$57,718	\$0
Net Interest	\$205,729	\$123,280	\$26,274	\$56,175	\$0
Net Income	\$57,653	\$34,547	\$7,363	\$15,742	\$0
Income Taxes ²	\$0	\$0	\$0	\$0	\$0
Other Taxes ³	\$5,383	\$3,226	\$687	\$1,470	\$0
<u>Residual⁴</u>	<u>(\$0)</u>	<u>(\$0)</u>	<u>(\$0)</u>	<u>(\$0)</u>	<u>\$0</u>
Total	\$501,250	\$306,911	\$63,234	\$131,105	\$0
Total Operating Revenues ⁵	\$1,368,769	\$1,043,593	\$82,328	\$192,058	\$50,790
less Wholesale Revenues	<u>(\$139,584)</u>	<u>(\$129,377)</u>	<u>(\$10,206)</u>	<u>\$0</u>	<u>\$0</u>
Total Retail Revenues	\$1,229,185	\$914,216	\$72,121	\$192,058	\$50,790
Total Retail Sales (MWH)	18,856,006				
Average Retail Rate (cents/kWh)	6.52	4.85	0.38	1.02	0.27

Footnotes:

- ¹ A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 76.4%, 3.4%, 11.0%, and 9.2%.
- ² Income Taxes include Federal Income Taxes, Other Income Taxes, Provision for Deferred Income Taxes (incl. credits).
- ³ Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.
- ⁴ Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).
- ⁵ Total Operating Revenues do not include revenues collected from state sales taxes.

**Table 1: Market Price Calculation for
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power**

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:		
Adjusted Retail Market Price *		4.56 ¢/kWh
Year Excess Capacity Ends		2000
(2) Using Capacity Charge and Energy Charge:		
Capacity Charge (\$/kW-yr):	NA	
Energy Charge (¢/kWh):	NA	
Average Market Price for Electricity:		none ¢/kWh
(3) Using an Exogenous Value:		
User-Input Wholesale Market Price for Electricity		2.59 ¢/kWh
T&D Line Loss Adjustment	6%	0.15 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
User-Input Retail Market Price for Electricity		3.61 ¢/kWh

*Market price for year 2000 and after based on average of CC/CT mix for two Arizona Utilities

Table 4
Assumptions Used in Estimating Stranded Costs for
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.85%
Reserve Margin =	15%

Fuel Price Forecast (1996\$/MMBtu):		User-Input	
1996	\$3.03	2004	\$2.58
1997	\$2.11	2005	\$2.72
1998	\$2.27	2006	\$2.73
1999	\$2.32	2007	\$2.73
2000	\$2.36	2008	\$2.73
2001	\$2.39	2009	\$2.71
2002	\$2.48	2010	\$2.71
2003	\$2.59	2011	\$2.72
		2012	\$2.75
		2013	\$2.71
		2014	\$2.73
		2015	\$2.75
		2016	\$2.80
		2017	\$2.85
		2018	\$2.90
		2019	\$2.95
		2020	\$3.00

Combined Cycle:	
Capital Cost	383.0 1996\$/kW
Fixed O&M	11.7 1996\$/kW/yr
Var O&M	0.200 1996mills/kW
Heat Rate	6,500 Btu/kWh

Schnitzer and EIA Annual Energy Outlook 1997

Combustion Turbine:	
Capital Cost	275.0 1996\$/kW
Fixed O&M	9.4 1996\$/kW/yr
Var O&M	0.100 1996mills/kW
Heat Rate	11,900 Btu/kWh

Schnitzer and EIA Annual Energy Outlook 1997

Month-1996	Total Monthly Energy (MWh)	Monthly Non- Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	-	-	-	-
Feb	-	-	-	-
Mar	-	-	-	-
Apr	-	-	-	-
May	-	-	-	-
Jun	-	-	-	-
Jul	-	-	-	-
Aug	-	-	-	-
Sep	-	-	-	-
Oct	-	-	-	-
Nov	-	-	-	-
Dec	-	-	-	-
TOTAL	26,178,809	5,687,218	20,491,591	-

Utility FERC Form 1 Data

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	\$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	3.61 c/kWh	

**Table 3b: Projecting Future Costs for
Salt River Project Agricultural Improvement & Power District**
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	1.24	1.24	18,856	233.4
1997	0.97	0.97	19,627	191.0
1998	0.69	0.69	20,430	140.9
1999	0.39	0.39	21,266	81.9
2000	0.06	0.06	22,135	12.9
2001	(0.08)	(0.08)	23,041	(19.2)
2002	(0.23)	(0.23)	23,983	(55.1)
2003	(0.38)	(0.38)	24,964	(94.9)
2004	(0.53)	(0.53)	25,985	(139.0)
2005	(0.69)	(0.69)	27,048	(187.8)
2006	(0.86)	(0.86)	28,154	(241.8)
2007	(1.03)	(1.03)	29,305	(301.2)
2008	(1.20)	(1.20)	30,504	(366.6)
2009	(1.38)	(1.38)	31,752	(438.6)
2010	(1.57)	(1.57)	33,050	(517.5)
2011	(1.76)	(1.76)	34,402	(604.1)
2012	(1.95)	(1.95)	35,809	(698.8)
2013	(2.15)	(2.15)	37,274	(802.5)
2014	(2.36)	(2.36)	38,798	(915.9)
2015	(2.57)	(2.57)	40,385	(1,039.6)
2016	(2.79)	(2.79)	42,037	(1,174.6)
2017	(3.02)	(3.02)	43,756	(1,321.7)
2018	(3.25)	(3.25)	45,546	(1,482.0)
2019	(3.49)	(3.49)	47,409	(1,656.4)
2020	(3.74)	(3.74)	49,348	(1,846.2)

Net Present Value of Stranded Costs (1996-2010) (1998\$): (\$440.3)

Net Present Value of Stranded Costs (1998-2012) (1998\$): (\$1,433.3)

Net Present Value of Stranded Costs (1998-2020) (1998\$): (\$3,927.3)

PV of Generation-Related Assets Not in Rates: \$0

Total Net Present Value of Stranded Costs (1998-2020) (1998\$): (\$3,927.3)

Assumed utility nominal discount rate 7.75%

System generation, excluding purchased power. Assumed escalation rate: 4.1%

Table 3a: Projections of Stranded Costs¹

Salt River Project Agricultural Improvement & Power District

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year,

CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.61	4.85	0.00
1997	3.88	4.85	0.00
1998	4.16	4.85	0.00
1999	4.46	4.85	0.00
2000	4.79	4.85	0.00
2001	4.93	4.85	0.00
2002	5.08	4.85	0.00
2003	5.23	4.85	0.00
2004	5.38	4.85	0.00
2005	5.54	4.85	0.00
2006	5.71	4.85	0.00
2007	5.88	4.85	0.00
2008	6.05	4.85	0.00
2009	6.23	4.85	0.00
2010	6.41	4.85	0.00
2011	6.60	4.85	0.00
2012	6.80	4.85	0.00
2013	7.00	4.85	0.00
2014	7.21	4.85	0.00
2015	7.42	4.85	0.00
2016	7.64	4.85	0.00
2017	7.87	4.85	0.00
2018	8.10	4.85	0.00
2019	8.34	4.85	0.00
2020	8.59	4.85	0.00

¹ All costs are in nominal dollars.

**Table 3b: Projecting Future Costs for
Salt River Project Agricultural Improvement & Power District**
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	1.24	1.24	18,856	233.4
1997	1.07	1.07	19,627	209.8
1998	0.89	0.89	20,430	182.4
1999	0.71	0.71	21,266	150.6
2000	0.51	0.51	22,135	113.9
2001	0.39	0.39	23,041	89.0
2002	0.25	0.25	23,983	60.9
2003	0.12	0.12	24,964	29.4
2004	(0.02)	(0.02)	25,985	(5.8)
2005	(0.17)	(0.17)	27,048	(45.1)
2006	(0.32)	(0.32)	28,154	(88.7)
2007	(0.47)	(0.47)	29,305	(137.2)
2008	(0.63)	(0.63)	30,504	(190.9)
2009	(0.79)	(0.79)	31,752	(250.2)
2010	(0.95)	(0.95)	33,050	(315.6)
2011	(1.13)	(1.13)	34,402	(387.7)
2012	(1.30)	(1.30)	35,809	(466.9)
2013	(1.49)	(1.49)	37,274	(554.0)
2014	(1.67)	(1.67)	38,798	(649.5)
2015	(1.87)	(1.87)	40,385	(754.1)
2016	(2.07)	(2.07)	42,037	(868.6)
2017	(2.27)	(2.27)	43,756	(993.8)
2018	(2.48)	(2.48)	45,546	(1,130.5)
2019	(2.70)	(2.70)	47,409	(1,279.7)
2020	(2.92)	(2.92)	49,348	(1,442.5)

Net Present Value of Stranded Costs (1996-2010) (1998\$): \$525.5

Net Present Value of Stranded Costs (1998-2012) (1998\$): (\$233.1)

Net Present Value of Stranded Costs (1998-2020) (1998\$): (\$2,090.1)

PV of Generation-Related Assets Not in Rates: \$0

Total Net Present Value of Stranded Costs (1998-2020) (1998\$): (\$2,090.1)

Assumed utility nominal discount rate 7.75%

System generation, excluding purchased power. Assumed escalation rate: 4.1%

Table 3a: Projections of Stranded Costs¹
Salt River Project Agricultural Improvement & Power District

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year.

CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.61	4.85	0.00
1997	3.78	4.85	0.00
1998	3.96	4.85	0.00
1999	4.14	4.85	0.00
2000	4.33	4.85	0.00
2001	4.46	4.85	0.00
2002	4.59	4.85	0.00
2003	4.73	4.85	0.00
2004	4.87	4.85	0.00
2005	5.01	4.85	0.00
2006	5.16	4.85	0.00
2007	5.32	4.85	0.00
2008	5.47	4.85	0.00
2009	5.64	4.85	0.00
2010	5.80	4.85	0.00
2011	5.98	4.85	0.00
2012	6.15	4.85	0.00
2013	6.33	4.85	0.00
2014	6.52	4.85	0.00
2015	6.72	4.85	0.00
2016	6.91	4.85	0.00
2017	7.12	4.85	0.00
2018	7.33	4.85	0.00
2019	7.55	4.85	0.00
2020	7.77	4.85	0.00

¹ All costs are in nominal dollars.

**Table 3b: Projecting Future Costs for
Tucson Electric Power Company**
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	3.49	3.49	6,852	239.2
1997	3.10	3.10	6,986	216.4
1998	2.65	2.65	7,122	188.5
1999	2.13	2.13	7,261	154.4
2000	1.53	1.53	7,403	113.3
2001	1.39	1.39	7,548	105.1
2002	1.25	1.25	7,695	96.4
2003	1.11	1.11	7,846	86.9
2004	0.96	0.96	7,999	76.6
2005	0.80	0.80	8,155	65.6
2006	0.65	0.65	8,315	53.7
2007	0.48	0.48	8,477	40.9
2008	0.31	0.31	8,643	27.2
2009	0.14	0.14	8,812	12.5
2010	(0.04)	(0.04)	8,984	(3.3)
2011	(0.22)	(0.22)	9,159	(20.2)
2012	(0.41)	(0.41)	9,338	(38.2)
2013	(0.60)	(0.60)	9,521	(57.5)
2014	(0.80)	(0.80)	9,707	(78.1)
2015	(1.01)	(1.01)	9,897	(100.0)
2016	(1.22)	(1.22)	10,090	(123.4)
2017	(1.44)	(1.44)	10,287	(148.3)
2018	(1.67)	(1.67)	10,488	(174.9)
2019	(1.90)	(1.90)	10,693	(203.1)
2020	(2.14)	(2.14)	10,902	(233.1)

Net Present Value of Stranded Costs (1996-2010) (1998\$)²: \$1,197.8

Net Present Value of Stranded Costs (1998-2012) (1998\$)²: \$778.9

Net Present Value of Stranded Costs (1998-2020) (1998\$)²: \$513.4

Net Present Value of Generation-Related Reg. Assets Not in Rates \$0.0

Net Present Value of Total Stranded Costs (1998-2020) (1998\$) \$513.4

Assumed utility nominal discount rate 7.75%

Table 3a: Projections of Stranded Costs¹

Tucson Electric Power Company

Scenario: Base year wholesale price based on average price of purchased power

Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year,
CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

O&M Costs

3.0%

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.02	6.12	0.00
1998	3.47	6.12	0.00
1999	3.99	6.12	0.00
2000	4.59	6.12	0.00
2001	4.73	6.12	0.00
2002	4.87	6.12	0.00
2003	5.01	6.12	0.00
2004	5.16	6.12	0.00
2005	5.32	6.12	0.00
2006	5.48	6.12	0.00
2007	5.64	6.12	0.00
2008	5.81	6.12	0.00
2009	5.98	6.12	0.00
2010	6.16	6.12	0.00
2011	6.34	6.12	0.00
2012	6.53	6.12	0.00
2013	6.72	6.12	0.00
2014	6.93	6.12	0.00
2015	7.13	6.12	0.00
2016	7.34	6.12	0.00
2017	7.56	6.12	0.00
2018	7.79	6.12	0.00
2019	8.02	6.12	0.00
2020	8.26	6.12	0.00

¹ All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Tucson Electric Power Company
 (thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	\$339,092	\$339,092			
O&M Minus Fuel	\$135,991	\$135,991			
Fuel	\$203,102	\$203,102			
Transmission	\$6,894		\$6,894		
Distribution	\$12,284			\$12,284	
<u>Customer/Sales</u>	<u>\$14,501</u>				<u>\$14,501</u>
Subtotal	\$372,771	\$339,092	\$6,894	\$12,284	\$14,501
<u>A&G¹</u>	<u>\$59,943</u>	<u>\$48,044</u>	<u>\$2,436</u>	<u>\$4,340</u>	<u>\$5,123</u>
Total	\$432,714	\$387,136	\$9,330	\$16,624	\$19,624
Plant Related Costs:					
Depreciation and Amort.	\$76,229	\$38,188	\$17,533	\$20,508	\$0
Net Interest	\$103,096	\$49,431	\$23,867	\$29,799	\$0
Net Income	\$11,982	\$5,745	\$2,774	\$3,463	\$0
Income Taxes ²	\$9,892	\$4,743	\$2,290	\$2,859	\$0
Other Taxes ³	\$37,604	\$18,030	\$8,705	\$10,869	\$0
<u>Residual⁴</u>	<u>\$21,514</u>	<u>\$10,315</u>	<u>\$4,980</u>	<u>\$6,218</u>	<u>\$0</u>
Total	\$260,317	\$126,452	\$60,149	\$73,716	\$0
Total Operating Revenues ⁵	\$693,031	\$513,588	\$69,479	\$90,341	\$19,624
less Wholesale Revenues	<u>(\$106,945)</u>	<u>(\$94,201)</u>	<u>(\$12,744)</u>	<u>\$0</u>	<u>\$0</u>
Total Retail Revenues	\$586,087	\$419,387	\$56,735	\$90,341	\$19,624
Total Retail Sales (MWH)	6,851,706				
Average Retail Rate (cents/kWh)	8.55	6.12	0.83	1.32	0.29

Footnotes:

¹ A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 80.2%, 4.1%, 7.2%, and 8.5%.

² Income Taxes include Federal Income Taxes, Other Income Taxes, Provision for Deferred Income Taxes (incl. credits).

³ Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

⁴ Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

⁵ Total Operating Revenues do not include revenues collected from state sales taxes.

**Table 1: Market Price Calculation for
Tucson Electric Power Company**
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

<u>Combined Cycle:</u>	<u>Total Costs:</u>	<u>1996 Real Levelized Costs</u>
Capital Costs	383.0 \$/kW	0.79 ¢/kWh
Fixed O&M	11.7 \$/kW-yr	0.22 ¢/kWh
Variable O&M	0.20 mills/kWh	0.02 ¢/kWh
Fuel	1.97 ¢/kWh	1.71 ¢/kWh
Sum of Levelized Costs:		2.74 ¢/kWh
Levelized Capacity Costs:		53.4 \$/kW-yr

<u>Combustion Turbine:</u>	<u>Total Costs:</u>	<u>1996 Real Levelized Costs</u>
Capital Costs	275.0 \$/kW	29.47 ¢/kWh
Fixed O&M	9.4 \$/kW-yr	9.26 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.13 ¢/kWh
Sum of Levelized Costs:		41.86 ¢/kWh
Levelized Capacity Costs:		39.3 \$/kW-yr

Capacity Factor Crossover for CC/CT	11%
Percent of CC energy in Market Price	99.6%
Percent of CT energy in Market Price	0.4%
Average Price of CC/CT mix	2.91 ¢/kWh

T&D Line Loss Adjustment	10%	0.30 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh

Adjusted Retail Market Price based on CC/CT mix 4.08 ¢/kWh

Year Excess Capacity Ends 2000

(2) Using Capacity Charge and Energy Charge:

Capacity Charge (\$/kW-yr):	NA
Energy Charge (¢/kWh):	NA
Average Market Price for Electricity:	none ¢/kWh

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity	1.59 ¢/kWh
T&D Line Loss Adjustment 10%	0.17 ¢/kWh
Order 888 Ancillary Services	0.10 ¢/kWh
Retailing A&G Adjustment	0.50 ¢/kWh
Other Retailing Costs Adjustment	0.27 ¢/kWh
User-Input Retail Market Price for Electricity	2.63 ¢/kWh

Table 4
Assumptions Used in Estimating Stranded Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996\$/MMBtu):		User-Input			
1996	\$3.03	2004	\$2.68	2012	\$2.75
1997	\$2.11	2005	\$2.72	2013	\$2.71
1998	\$2.27	2006	\$2.73	2014	\$2.73
1999	\$2.32	2007	\$2.73	2015	\$2.75
2000	\$2.36	2008	\$2.73	2016	\$2.80
2001	\$2.39	2009	\$2.71	2017	\$2.85
2002	\$2.48	2010	\$2.71	2018	\$2.90
2003	\$2.59	2011	\$2.72	2019	\$2.95
				2020	\$3.00

Source: Exhibit_(RAR-6)

Combined Cycle:	
Capital Cost	383.0 1996\$/kW
Fixed O&M	11.7 1996\$/kW/yr
Var O&M	0.200 1996mills/kW
Heat Rate	6,500 Btu/kWh

Schnitzer, in Docket #16705, Direct Testimony on behalf of TX
OPUC, and EIA Annual Energy Outlook 1997

Combustion Turbine:	
Capital Cost	275.0 1996\$/kW
Fixed O&M	9.4 1996\$/kW/yr
Var O&M	0.100 1996mills/kW
Heat Rate	11,900 Btu/kWh

Tellus Institute, Energy Innovations- A Prosperous Path
to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	57%
Max. Annual Load (MW)	1619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1862
Cut-off point:	11.0%
Load at above Cut-off (MW)	1527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
Percentage of Energy Supplied by CTs	0.4%
Percentage of Energy Supplied by CCs	99.6%

Average Wholesale Market Price	
of Electricity Based	29.09 \$/MWh
on CC/CT Method	2.91 c/kWh
T&D Line Loss Adjustment	0.30 c/kWh
Order 888 Ancillary Services	0.10 c/kWh
Retailing A&G Adjustment	0.50 c/kWh
Other Retailing Costs Adjstmt	0.27 c/kWh

Month-1996	Total Monthly Energy (MWh)	Monthly Non- Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	855,793	261,591	594,202	1,062
Feb	763,804	224,230	539,574	1,043
Mar	806,714	236,376	570,338	961
Apr	836,467	249,242	587,225	1,255
May	920,007	212,419	707,588	1,410
Jun	992,763	213,336	779,427	1,519
Jul	1,144,033	262,289	881,744	1,619
Aug	1,131,929	276,469	855,460	1,608
Sep	1,012,034	307,068	704,966	1,369
Oct	1,032,968	378,436	654,532	1,355
Nov	942,033	383,554	558,479	987
Dec	994,999	373,905	621,094	1,102
TOTAL	11,433,544	3,378,915	8,054,629	1,619

Utility FERC Form 1 Data

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	\$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	2.63 c/kWh	

CC-CT Market Price Worksheet for:

Tucson Electric Power Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user.

Month	Total Monthly Energy (MWh)	Monthly Non- Requirements Sales for Resale & Associated Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
	USER-INPUT	USER-INPUT		USER- INPUT			
Jan	855,793	261,591	594,202	1,062	961	81%	781
Feb	763,804	224,230	539,574	1,043			
Mar	806,714	236,376	570,338	961			
Apr	836,467	249,242	587,225	1,255			
May	920,007	212,419	707,588	1,410			
Jun	992,763	213,336	779,427	1,519			
Jul	1,144,033	262,289	881,744	1,619			
Aug	1,131,929	276,469	855,460	1,608			
Sep	1,012,034	307,068	704,966	1,369			
Oct	1,032,968	378,436	654,532	1,355			
Nov	942,033	383,554	558,479	987			
Dec	994,999	373,905	621,094	1,102			
TOTAL	11,433,544	3,378,915	8,054,629	1,619	961	0.81	781

LOAD FACTOR

57%

Max. Annual Load (MW)

1,619

Min. Monthly Peak (MW)

961

Load Factor for Min. Monthly Load

0.81

Effective Min. Annual Load

781

Max. Load + Reserve Margin (MW)

1,862

Cut-off point:

11%

Load at above Cut-off (MW)

1,527

Ratio between 0.92
total energy under load curve
and total monthly energy

Total Energy under Load Curve (MWh)

10,513,248

Energy Supplied by CTs (MWh)

44,397

Ratio of energy supplied by CTs

0.4%

Energy Supplied by CCs (MWh)

10,468,851

Ratio of energy supplied by CCs

99.6%

check

0

CC

Capital Cost	41.67	\$/kW times	1,527	MW	equals	63,624,506	dollars	\$	27.43	MWh
Fixed O&M	11.70	\$/kW times	1,527	MW	equals	17,864,161	dollars			
Var O&M	0.20	mills/kWh times	8,020,614	MWh	equals	1,604,123	dollars			
Fuel	1.71	cents/kWh times	8,020,614	MWh	equals	136,950,332	dollars			

CT

Capital Cost	29.92	\$/kW times	335	MW	equals	10,023,160	dollars	\$	418.61	MWh
Fixed O&M	9.40	\$/kW times	335	MW	equals	3,148,987	dollars			
Var O&M	0.10	mills/kWh times	34,015	MWh	equals	3,401	dollars			
Fuel	3.13	cents/kWh times	34,015	MWh	equals	1,063,294	dollars			

TOTAL 234,281,965 dollars

Tot Energy 8,054,629 MWh
in real LDC

OUTPUT

Average Market Price of Electricity - 1996

29.09	\$/MWh
2.91	c/kWh

**Table 3b: Projecting Future Costs for
Tucson Electric Power Company**

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	3.49	3.49	6,852	239.2
1997	3.06	3.06	6,986	213.8
1998	2.56	2.56	7,122	182.4
1999	1.98	1.98	7,261	143.6
2000	1.30	1.30	7,403	96.3
2001	1.16	1.16	7,548	87.3
2002	1.01	1.01	7,695	77.6
2003	0.86	0.86	7,846	67.2
2004	0.70	0.70	7,999	56.0
2005	0.54	0.54	8,155	43.9
2006	0.37	0.37	8,315	30.9
2007	0.20	0.20	8,477	17.0
2008	0.02	0.02	8,643	2.1
2009	(0.16)	(0.16)	8,812	(13.9)
2010	(0.34)	(0.34)	8,984	(31.0)
2011	(0.54)	(0.54)	9,159	(49.2)
2012	(0.74)	(0.74)	9,338	(68.7)
2013	(0.94)	(0.94)	9,521	(89.5)
2014	(1.15)	(1.15)	9,707	(111.7)
2015	(1.37)	(1.37)	9,897	(135.3)
2016	(1.59)	(1.59)	10,090	(160.5)
2017	(1.82)	(1.82)	10,287	(187.2)
2018	(2.06)	(2.06)	10,488	(215.7)
2019	(2.30)	(2.30)	10,693	(246.0)
2020	(2.55)	(2.55)	10,902	(278.1)

Net Present Value of Stranded Costs (1996-2010) (1998\$)²: \$1,050.9

Net Present Value of Stranded Costs (1998-2012) (1998\$)²: \$599.1

Net Present Value of Stranded Costs (1998-2020) (1998\$)²: \$257.2

Net Present Value of Generation-Related Reg. Assets Not in Rates \$0.0

Net Present Value of Total Stranded Costs (1998-2020) (1998\$) \$257.2

Assumed utility nominal discount rate 7.75%

Table 3a: Projections of Stranded Costs¹

Tucson Electric Power Company

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:

User Exogenous Input in Base Year.

CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates:

See Table 4: Scenario Assumptions

O&M Costs

3.0%

Year when excess capacity ends:

2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.06	6.12	0.00
1998	3.56	6.12	0.00
1999	4.14	6.12	0.00
2000	4.82	6.12	0.00
2001	4.96	6.12	0.00
2002	5.11	6.12	0.00
2003	5.26	6.12	0.00
2004	5.42	6.12	0.00
2005	5.58	6.12	0.00
2006	5.75	6.12	0.00
2007	5.92	6.12	0.00
2008	6.10	6.12	0.00
2009	6.28	6.12	0.00
2010	6.47	6.12	0.00
2011	6.66	6.12	0.00
2012	6.86	6.12	0.00
2013	7.06	6.12	0.00
2014	7.27	6.12	0.00
2015	7.49	6.12	0.00
2016	7.71	6.12	0.00
2017	7.94	6.12	0.00
2018	8.18	6.12	0.00
2019	8.42	6.12	0.00
2020	8.67	6.12	0.00

¹ All costs are in nominal dollars.

**Table 3b: Projecting Future Costs for
Tucson Electric Power Company**

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen. ¹ (GWh)	Stranded Costs (\$ million)
1996	3.49	3.49	6,852	239.2
1997	3.14	3.14	6,986	219.1
1998	2.73	2.73	7,122	194.7
1999	2.28	2.28	7,261	165.4
2000	1.76	1.76	7,403	130.3
2001	1.63	1.63	7,548	123.0
2002	1.50	1.50	7,695	115.1
2003	1.36	1.36	7,846	106.5
2004	1.22	1.22	7,999	97.3
2005	1.07	1.07	8,155	87.2
2006	0.92	0.92	8,315	76.4
2007	0.76	0.76	8,477	64.8
2008	0.60	0.60	8,643	52.3
2009	0.44	0.44	8,812	38.8
2010	0.27	0.27	8,984	24.3
2011	0.10	0.10	9,159	8.9
2012	(0.08)	(0.08)	9,338	(7.7)
2013	(0.27)	(0.27)	9,521	(25.5)
2014	(0.46)	(0.46)	9,707	(44.5)
2015	(0.65)	(0.65)	9,897	(64.7)
2016	(0.86)	(0.86)	10,090	(86.4)
2017	(1.06)	(1.06)	10,287	(109.4)
2018	(1.28)	(1.28)	10,488	(134.0)
2019	(1.50)	(1.50)	10,693	(160.2)
2020	(1.73)	(1.73)	10,902	(188.1)
Net Present Value of Stranded Costs (1996-2010) (1998\$)²:				\$1,345.2
Net Present Value of Stranded Costs (1998-2012) (1998\$)²:				\$958.9
Net Present Value of Stranded Costs (1998-2020) (1998\$)²:				\$770.0
Net Present Value of Generation-Related Reg. Assets Not in Rates				\$0.0
Net Present Value of Total Stranded Costs (1998-2020) (1998\$)				\$770.0

Assumed utility nominal discount rate 7.75%

Table 3a: Projections of Stranded Costs¹
Tucson Electric Power Company

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on: User Exogenous Input in Base Year,
 CC/CT Mix Method in Year Excess Capacity Ends
 Escalation Rates: See Table 4: Scenario Assumptions
 O&M Costs 3.0%
 Year when excess capacity ends: 2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	2.98	6.12	0.00
1998	3.39	6.12	0.00
1999	3.84	6.12	0.00
2000	4.36	6.12	0.00
2001	4.49	6.12	0.00
2002	4.63	6.12	0.00
2003	4.76	6.12	0.00
2004	4.91	6.12	0.00
2005	5.05	6.12	0.00
2006	5.20	6.12	0.00
2007	5.36	6.12	0.00
2008	5.52	6.12	0.00
2009	5.68	6.12	0.00
2010	5.85	6.12	0.00
2011	6.02	6.12	0.00
2012	6.20	6.12	0.00
2013	6.39	6.12	0.00
2014	6.58	6.12	0.00
2015	6.77	6.12	0.00
2016	6.98	6.12	0.00
2017	7.18	6.12	0.00
2018	7.40	6.12	0.00
2019	7.62	6.12	0.00
2020	7.85	6.12	0.00

¹ All costs are in nominal dollars.

Projected Prices of Natural Gas Used for Power Generation

Assumed inflation rate	3%
------------------------	----

	EIA (Mountain) (1995\$/Mmbtu) (1)	AZ projected 12% (2)		AZ projected (\$1996/Mmbtu)
1995	1.69	\$ 1.77	Actual	\$ 1.82
1996	2.07	\$ 3.03		\$ 3.03
1997	1.83	\$ 2.05		\$ 2.11
1998	1.96	\$ 2.20		\$ 2.27
1999	2.01	\$ 2.25		\$ 2.32
2000	2.05	\$ 2.29		\$ 2.36
2001	2.07	\$ 2.32		\$ 2.39
2002	2.15	\$ 2.41		\$ 2.48
2003	2.24	\$ 2.51		\$ 2.59
2004	2.32	\$ 2.60		\$ 2.68
2005	2.35	\$ 2.64		\$ 2.72
2006	2.36	\$ 2.65		\$ 2.73
2007	2.36	\$ 2.65		\$ 2.73
2008	2.36	\$ 2.65		\$ 2.73
2009	2.35	\$ 2.63		\$ 2.71
2010	2.35	\$ 2.63		\$ 2.71
2011	2.36	\$ 2.64		\$ 2.72
2012	2.39	\$ 2.67		\$ 2.75
2013	2.35	\$ 2.63		\$ 2.71
2014	2.37	\$ 2.65		\$ 2.73
2015	2.39	\$ 2.67		\$ 2.75

Source: (1) -- Annual Energy Outlook, 1997

(2) -- Arizona prices are assumed to be 12% above regional forecast. See Page 2 of 2.

Historical prices of gas used for electric generation (Mountain Region)

(\$/Mcf nominal)

	1991	1992	1993	1994	1995	1996	
Mountain	\$ 1.87	\$ 2.07	\$ 2.48	\$ 2.09	\$ 1.74	\$ 2.33	
Arizona	\$ 2.06	\$ 2.28	\$ 2.88	\$ 2.23	\$ 1.77	\$ 3.03	
Utah	\$ 1.72	\$ 1.87	\$ 2.31	\$ 2.42	\$ 2.26	\$ 1.83	
Nevada	\$ 1.78	\$ 1.91	\$ 2.45	\$ 1.99	\$ 1.71	\$ 2.12	
New Mexico	\$ 1.73	\$ 1.99	\$ 2.23	\$ 1.99	\$ 1.57	\$ 2.31	
Wyoming	\$ 3.51	\$ 3.33	\$ 3.44	\$ 5.80	\$ 8.32	\$ 12.59	
Montana	\$ 4.33	\$ 3.30	\$ 2.83	\$ 1.21	\$ 3.84	\$ 2.89	
Idaho	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Colorado	\$ 2.14	\$ 2.14	\$ 2.53	\$ 2.21	\$ 1.74	\$ 2.09	
AZ-Mount	\$ 0.19	\$ 0.21	\$ 0.40	\$ 0.14	\$ 0.03	\$ 0.70	Average
(AZ-Mou)/Mou	10%	10%	16%	7%	2%	30%	12%

Source: EIA, 1996, Natural Gas Annual

SCHEDULE H
RETAILING FUNCTIONS

NYS PSC CASE
NO. 96 E-0898
RG&E RESTRUCTURING

Notes:

- (1) P = Primary responsibility for function. S = Secondary responsibility for function. Relationship to be governed and further clarified by Operating Agreement under distribution tariff.
- (2) The relationship between the ISO/PE (Independent System Operator/Power Exchange) and the disco is not yet clear. For purposes of developing a complete list of LSE/disco activities, the disco is assumed to act as a local extension of the ISO/PE for activities required to maintain system reliability and security.
- (3) Functions that are the sole responsibility of the disco have been eliminated from this list.

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
1. System requirements forecasting, planning, and budgeting (Forecast future energy delivery system capability/ infrastructure requirements. Prepare detailed plans and budgets to modify system to meet requirements.)	S Provide energy sales forecasts for disco aggregation	P All activities
2. Energy system work management, including prioritization, scheduling, and coordination (Prioritize, schedule, and coordinate the efficient use of labor and materials to meet customer requests, as well as the construction and maintenance of the energy system.)	S Work with disco to set emergency and non-emergency work priority and response time guidelines	P All activities
3. Design and documentation of system operating rules, operating agreements, and operating procedures (Manage real-time construction and maintenance of the delivery system, agreements with energy suppliers and the ISO with respect to delivery and receipt of energy, protection of the system during extreme operating conditions such as load shedding, voltage and pressure reductions, and requests for fuel switching and curtailment of gas or electric usage.)	S Work with disco to design operating rules, agreements, and procedures	P All activities
4. Negotiation and administration of contracts for balancing and ancillary services (Ancillary services required for secure and reliable delivery of energy; balancing services to cover variances between real-time deliveries and real-time energy consumption. Includes accounting and invoice processing support.)	S May contract with a non-disco provider for some ancillary services, as provided by FERC rules	P All activities

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
5. Short term forecasting and scheduling of system energy requirements (Daily, monthly, and seasonal energy forecasts, short-term scheduling of energy receipt and delivery, short-term scheduling of balancing and ancillary services.)	<i>S</i> Produce daily, monthly, and seasonal energy forecasts for customers with real-time meters. Schedule deliveries to disco interchange point/city gate based on those forecasts, and based on load shapes for customers without real-time meters.	<i>P</i> All other activities, including developing standard load shapes and load-shape-based forecasts for use by LSEs where real-time meters are lacking; forecasting total system energy requirements; and aggregating LSE delivery schedules to determine requirements for load balancing and ancillary services.
6. Real-time control and monitoring of the energy delivery system (Real-time use of energy balancing and ancillary services, real-time interaction with ISO and third-party suppliers of energy, real-time application and enforcement of system operating rules, operating agreements, and operating procedures, real-time interpretation of SCADA information)	<i>S</i> Respond to disco/ISO operating requirements real-time	<i>P</i> All other activities
7. Energy imbalance management and coordination for the distribution area (Identify imbalances, trade imbalances, acquire or curtail energy supply to resolve imbalances, allocate imbalance costs, set imbalance performance standards and monitor compliance among market participants, acquire and manage/process real-time customer meter data for imbalance diagnosis)	<i>S</i> Provide data as required by agreement with disco	<i>P</i> All other activities
8. Management of system restoration (Performance of tasks required to analyze, coordinate, schedule, and facilitate restoration of the energy supply system in a timely, safe manner.)	<i>S</i> Provide personnel and resources to support restoration activities	<i>P</i> All other activities

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
<p>9. Dispatch of field personnel for unscheduled energy system work (To respond to same-day requests for customer service and response to emergency or outage situations.) <i>Note:</i> This may include repairs of equipment and facilities on the customer side of the meter if such repairs will facilitate a rapid return to service.</p>	<p><i>S</i> Depending on terms of agreement with disco, may receive first customer notification of outages or emergencies, may dispatch field personnel to make initial diagnosis of problem, may dispatch field personnel for repairs of customer-side-of-the-meter equipment and facilities.</p>	<p><i>P</i> All other activities, possibly including tracking of costs for charge-back to customer's LSE</p>
<p>10. Real-time response to customer service and field personnel inquiries for energy delivery facilities' information (Provide data for stake-outs and to respond to such customer requests as when they can expect to return to service after an outage. Future customer requests could address such customer issues as interruptions of customer/generator bilateral contracts for operating reasons.)</p>	<p><i>S</i> Depending on terms of agreement with disco, may provide interface between direct retail customer query and disco.</p>	<p><i>P</i> All other activities</p>
<p>11. Coordination and maintenance of emergency response plans and training (Develop, coordinate, and document emergency response plans, and associated training requirements, including emergency response drills.) <i>Note:</i> Emergencies include, for example, wire-down reports (including phone and cable wire-downs), individual or local service outages, large-scale service outages (e.g., ice storms), pole and cable hits, and pipe dig-ups.</p>	<p><i>S</i> Participate in development of emergency response plans and ensure personnel are trained as agreed by LSEs and disco</p>	<p><i>P</i> All other activities</p>
<p>12. Deliver energy from the city gate/interchange point to the end-user</p>	<p><i>S</i> Schedule energy deliveries (plus losses) to city gate/interchange point and inform disco accordingly</p>	<p><i>P</i> All other activities</p>

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
<p>13. Distributed generation/back-up generation/buy-back power management of interaction with energy system (Identify interface requirements, accommodate partial and full outages of customer-sited generation, analyze and resolve power quality and system operating issues due to such generation, set and enforce performance standards.) <i>Note:</i> It is not clear whether the LSE or disco would be best positioned to have ultimate authority and accountability over customer-sited generation.</p>	<p><i>S</i> Purchase all power from customer generators (not sold to other LSEs) and provide back-up power. Depending on agreement with disco, may interface between disco and customer.</p>	<p><i>P</i> Set and enforce interface requirements, including imposing non-performance penalties.</p>
<p>14. Power quality (Accept customer calls, diagnose problems, determine problem accountability (calling customer, other customers, disco facilities), prioritize, schedule, and coordinate problem resolution, implement problem resolution.) <i>Note:</i> Power quality may require a collaborative approach among some or all LSEs, the disco and customers and providers with power quality concerns to address multi-customer or cross-customer issues.</p>	<p><i>P</i> All other activities</p>	<p><i>S</i> Provide diagnostic support upon LSE request, and resolve power quality problems attributable to disco facilities or operations, including tracking costs and billing LSEs as appropriate</p>
<p>15. Market research (Collect, analyze, and report customer data for the support of planning and development of new and existing products and services.)</p>	<p><i>P</i> All other activities</p>	<p><i>S</i> Work with LSEs to unbundle wholesale distribution services to allow for product differentiation</p>
<p>16. Quality service management (Serve as an internal advocate for the customer; collect and analyze customer data for feedback on service performance and product quality.)</p>	<p><i>P</i> All other activities</p>	<p><i>S</i> Work with LSEs to set and maintain delivery service quality standards and performance</p>

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
17. Marketing, including pricing design (Identify value through products and services to customers and customer subgroups based on needs and desires identified through market research. Coordinate cross-functional teams for product design and pricing, positioning, and promotion of the product and service.) <i>Note:</i> Does not include regulated tariffs, addressed separately below.	^P All other activities	^S Work with LSEs to unbundle wholesale distribution services to allow for product differentiation.
18. Sales (Prospecting, communicating, and selling products and services to customers)	^P All activities	N/A
19. Maintenance of third party relationships (Maintain relationships with third parties who also have relationships with retail customers for energy or energy-related products and services.) <i>Note:</i> Includes conducting training for trade allies, working with local governments to conduct municipally-mandated undergrounding and other activities, acting on behalf of low-income customers to facilitate Department of Social Service activities, responding to fire department requests to address possible gas leaks and wire-downs, working with various disaster and emergency offices and organizations, interfacing with local governments and public interest groups, participating in IEEE standards groups, and, in the future, negotiating services, prices, performance standards, and data exchange arrangements with LSEs.)	^S Maintain relationships with discos, other LSEs, and joint ventures/alliances/suppliers.	^P Maintain relationships with emergency- and safety-related organizations, LSE suppliers, and DSS and other parties involved in providing funding for services to retail customers who can pay full price for them.
20. Responding to customer inquiries and requests (Includes turn-on/shut-off, requests for outage-related information, application processing, requests for account information, and requests for information regarding energy technologies and end-uses.)	^P All other activities	^S Implement turn-on/shut-off. Provide information upon request concerning the status of outage whose restoration being managed by the disco

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
<p>21. Management of the revenue collection process (Obtain consumption information, bill customer consistent with service agreement, accept and process payments, manage delinquent accounts, maintain accuracy and integrity of customer records.) <i>Note:</i> Includes design, operations, and maintenance of CIS and other information systems infrastructure.</p>	<p><i>P</i> Conduct this task at the retail level, for revenue collected directly from retail customers</p>	<p><i>S</i> Conduct this task at the wholesale level, for revenue collected from LSEs</p>
<p>22. Facilitation of customer trading of imbalances and storage balances (Provide customers with an efficient means of engaging in transactions with other customers to mitigate expense associated with energy imbalances.) <i>Note:</i> Responsibility and practices may be different for gas and electricity.</p>	<p><i>P</i> Conduct this task at the retail level, for retail customers with real-time meters who have been given the option in their retail product design of avoiding the flow-through of wholesale imbalance charges</p>	<p><i>S</i> Conduct this task at the wholesale level, for LSEs only</p>
<p>23. Development and implementation of public involvement programs (Communicate with the general public for purpose of education, information exchange, and to address customer complaints which may otherwise elevate to a PSC complaint.) <i>Note:</i> To facilitate development of the competitive retail market, all customer-interface activities should eventually be conducted by the LSE rather than the disco.</p>	<p><i>P</i> All other activities</p>	<p><i>S</i> Provide funding through public policy charge</p>
<p>24. Regulatory coordination and tariff design (Serve as the liaison between the Company and regulatory bodies, design tariffs, conduct rate cases.) <i>Note:</i> Disco and regulated LSE will remain under rate-of-return and other State regulation.</p>	<p><i>S</i> Regulated LSE will have retail tariff responsibilities that competitive LSEs will not. All LSEs may need to comply with licensing and reporting requirements.</p>	<p><i>P</i> Wholesale distribution tariff and other regulatory coordination activities.</p>

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
25. Forecasting of customer energy requirements (Forecasting of electric system and installed reserve capacity and energy required to meet customer demand for electric energy, including forecasts for specific groups and/or individual customers as required by future service/tariff designs. Forecasts can be daily, monthly, seasonally and/or long-term.)	<i>P</i> All other activities	<i>S</i> Aggregate LSE forecasts and produce total system load forecasts for distribution system planning and imbalance service requirements
26. Scheduling of capacity and energy purchases and delivery to the service area (Capacity (e.g., installed reserve) and energy procurement and delivery scheduling consistent with forecasts of customer requirements.) <i>Note:</i> Responsibility and practices may be different for gas and electricity.	<i>P</i> All other activities	<i>S</i> Scheduling of spot market energy purchases and stand by capacity to eliminate local load imbalances
27. Negotiation and administration of contracts for procurement of energy and associated delivery services (Consistent with forecasted capacity and energy requirements, negotiate contracts for the procurement of capacity, energy, and wholesale delivery services. Administration of the contracts includes accounting and invoice processing support.) <i>Note:</i> Assumes that LSEs are responsible for pipeline and installed reserve capacity to meet their customers' needs. It may be that electric installed reserves are more efficiently purchased by the disco for its service area load and passed through in the wholesale distribution tariff.	<i>P</i> All other activities	<i>S</i> Capacity and energy contracts associated with long-term imbalance trends.

Tellus Institute Strandable Costs Calculation Model

1. Introduction

This document serves as a guide to the Tellus Institute approach to calculating strandable costs for an electric utility. It provides an overview of the methodology, inputs, and scenario development used in calculating utility-specific strandable costs. To facilitate the strandable costs calculation, a simple model was developed consisting of four interdependent analyses: an unbundling analysis, a market price analysis, a financial evaluation of strandable costs in a single year, and a projection of strandable costs over a specified period of analysis. Since each utility faces a unique set of circumstances entering into the competitive generation market, the Tellus Strandable Costs Model (SCM) is designed to provide an analysis of the specific financial conditions for each utility.

It is important to recognize that any estimates of strandable costs will include many uncertainties, and will be subject to debate by many parties. Therefore, estimates of strandable costs should be as simple and as clear as possible. This information guide is intended to explain Tellus' SCM modeling assumptions and should assist readers in following the logic of the calculations in the model. In addition, Tellus recommends that SCM estimates should be prepared for a variety of scenarios and sensitivities to indicate how the stranded costs might change with different input assumptions.

2. Methodology

Strandable costs can generally be defined as the difference between the competitive market value and the regulated book value (or embedded cost value) of a utility's generation assets. Therefore, the general approach to estimating strandable costs is to calculate the difference between (a) the utility's embedded generation cost value over a specified period of time, and (b) the market price for power in the region over the same period of time. The SCM follows from this basic equation. As such, the SCM calculates a utility's *potentially strandable* costs, as opposed to costs that would actually be stranded (e.g., as a result of customers actually leaving the utility's system for an alternative supplier). Strandable costs represents the maximum amount of costs that may become stranded in a retail competitive generation market.

The SCM includes four main components: a market price calculation; an unbundling calculation of the utility's average retail generation price; a calculation of strandable costs in the base year; and a projection of strandable costs over a user specified period of analysis.

Market Price Calculation

The user can choose from three different methods to determine the average generation market price value for the first year of analysis, based on: 1) a least cost mix of new natural gas combined cycle and combustion turbine generating units; 2) user-specified capacity and energy charges; or 3) an exogenous user-input value. In all cases, the estimate of market price is based on the assumption that competitive generation companies in the utility's region provide energy sufficient to meet the utility's entire load. In other words, the market price represents the average cost of power in the region, as opposed to the marginal cost.

The first option derives a competitive market price based on the cost of an optimal combination of new natural gas combined cycle and combustion turbine units. This method requires the user to make assumptions about current and future fuel (gas) prices, a discount rate, and fixed charge factor. A real levelized average market price based on this CC/CT mix represents the market price for the first year of analysis.

For the second option, the competitive market price is based on user-specified energy and capacity charges. Specific energy and capacity price information could be based on existing state or regional market price proxy values, such as competitive wholesale prices, avoided cost values, etc.

Finally, the user has the option of simply entering an exogenous, average market price value.

Unbundled Generation Costs

The user enters utility-specific costs and revenues for a historical year using information provided by utilities to FERC. Unbundled costs are calculated by allocating the data into generation, transmission, distribution, and customer related expenses, according to FERC accounting categories. After the expenses and revenues are spread among these categories, further adjustments are made regarding wholesale transactions to produce a final estimate of embedded costs per category. An average unbundled rate (in cents/kWh) for each component is then computed by dividing embedded costs by ultimate sales to customers.

Strandable Costs - Base Year

Strandable costs for the first year of analysis are calculated based on a comparison of the utility's unbundled generation rate and the assumed market price. The user has the option of assuming a transition charge, which allows the utility to recover from customers a portion of stranded costs. The "net" revenue reduction represents the strandable costs, less any revenues recovered through the transition charge. The utility's net revenue reduction is then compared to how it will impact the utility's shareholders, as well as its average retail customer.

Strandable Cost - Projections

Finally, the SCM allows the user to develop scenario projections based on a fixed time horizon (not to exceed 10 years). The method for determining the market price over the projected time period will depend on whether or not the utility has excess capacity, and if that excess capacity is anticipated to end during the period of the analysis. If the utility does have excess capacity which is expected to end within the period of analysis, then regardless of what method is used to calculate market price in the base year, the model will automatically switch to the CC/CT Mix market price in the year that excess capacity ends, since this price will best represent the marginal cost of generation in the future. In that year, the CC/CT Mix market price will reflect a price that is escalated from the base year CC/CT Mix price according to user's assumed escalation rates for fuel, energy and fixed cost components.

Regardless of which market price methodology is used, the user can make assumptions about escalation rates for the various market price components (e.g., energy and demand charges). The user may also choose to enter an escalation rate for the utility's average unbundled generation price projection. And finally, the user may estimate the utility's future electricity sales either by entering a forecast of sales over the projection period or by escalating the base year sales at a specified rate.

The computation and inputs for the SCM are discussed in greater detail below.

3. Inputs and Computational Analysis

The inputs necessary to calculate strandable costs will come from a number of utility-specific and industry-specific sources. Examples of such sources are: the utility's FERC FORM 1, current utility Integrated Resource Plans and Annual Reports, and various fuel cost forecasts, and supply and demand forecasts for the region.

Unbundling Generation Costs

The first step in the valuation of a utility's existing generation assets is to isolate those costs and revenues which are associated with generation-related assets. To do this, the models' unbundling input spreadsheet requires that information from the utility's Operating Income (FERC FORM 1 pp. 114-119), Electric Operation and Maintenance Expenses (FERC FORM 1 pp. 320-323), Customer Sales and Operating Revenues (FERC FORM 1 pp. 300-304), and Electric Utility Plant (FERC FORM 1 pp. 220-221) be entered as inputs.

The model uses a simple method to unbundle these costs and revenues by allocating the Operation & Maintenance Expenses, Plant Related Expenses, and Operating Revenues in rate base into generation-related, transmission-related, distribution-related and customer-related costs and revenues, according to each category's contribution to net plant (or gross plant in the case of depreciation). In the case of Administrative and General Expenses, the user has the option to directly allocate these costs to any of the four cost components.

Total Operating Revenues represent the value of assets in rate base, for both wholesale and retail operations. In order to obtain the utility's total *retail* revenues, a wholesale revenue adjustment must be made to Total Operating Revenues. The Adjusted Retail Revenues are then converted to an average retail rate (cents/kWh) per cost component by dividing the totals by total retail sales. The final result is an estimate of unbundled generation, distribution, transmission, and customer costs for the utility's retail operations.

Market Price

Estimating a competitive market price for a specific state or region is likely to be highly uncertain. In order to accommodate different levels of information about the market price for power, the model allows for three market price options to be pursued and examined in separate scenarios.

As discussed earlier, the first option utilizes cost information for a newly built Combustion Turbine (CT) and a newly built Combined Cycle (CC) plant to determine a market price based on the optimal mix of CTs and CCs to serve the utility's load profile. This estimation of market price is likely to represent a "high" market price value. The model offers the user the option to input plant-related cost information for a new CC or CT, or to simply use the default values provided from the *EPRI Technical Assessment Guide*. In addition, financial assumptions such as the fixed charge factor, and fuel cost escalation and inflation rates may be input or default values may be used.

To determine the likely future mix of CCs and CTs for a utility's system, the SCM conducts a crossover calculation, based on a comparison of fixed and variable costs, to determine the capacity factor below which CTs will operate and above which CCs will operate. The outcome of the crossover calculations provides the combination of CCs and CTs which would serve this utility's system at the lowest cost, optimal or least cost system. In order to correctly compare the unbundled generation rate to the CC/CT market price in the strandable costs comparison, it is necessary to adjust the CC/CT market price to reflect the generation-related A&G costs the utility would likely incur in providing this electricity, just as they are reflected in the unbundled generation rate. The amount of the CC/CT market price A&G adjustment is based on the historical cost of generation related A&G, as reflected in the unbundling spreadsheet.

The second market price option allows for the choice of representative energy and demand charges to be input. Using these charges, along with the utility's load data, the model calculates the average market generation price in costs/kWh. Using this method, the user can create a range of high, medium, and low market prices assumptions that are derived from a range of user input energy and demand charges.

The third market price option simply allows the user to directly input a market generation price (in cents/kWh). Again, with this straightforward method, the user can create a range of market price assumptions.

Strandable Costs - Base Year

Once the unbundled generation costs for the utility have been estimated by the model, and a market price has been estimated, strandable costs for the base year can be calculated as the difference between the two. The model presents the output for a one year strandable cost calculation. The model calculates the net reduction in generation costs (in ¢/kWh) as the difference between the average utility generation cost and the competitive market price. If a transition charge is assumed, then the net reduction in generation costs will be reduced accordingly. Finally, retail sales are used to determine the strandable costs (i.e., revenue reduction) in this one year.

In turn, the model examines the impact on the shareholders by examining the Revenue Reductions due to competition as a percentage of the following costs:

- Net Income plus Income Taxes (or Gross Income)
- Gross Income plus Depreciation
- Gross Income plus Depreciation and Net Interest.

The first comparison is likely the most important, since the financial viability of a utility is typically measured in terms of its ability to pay its shareholders and its income taxes. A scenario in which there would be a sharing of stranded costs (e.g., using a transition charge) would clearly alleviate the impact on shareholders, yet not provide as a large reduction in the average generation rate to ratepayers.

4. Strandable Costs - Projections

The SCM allows for scenarios that calculate potential strandable costs over a multiple year period. The importance of analyzing this information is that while the first year may reveal significant initial strandable costs for a utility, the utility's strandable costs over a longer period of analysis may provide an entirely different picture. For example, a utility with stranded costs in the base year may, within a few years, face no strandable costs, and may even receive profits as a result of its embedded generation costs falling below expected future market prices.

In this multi-year period analysis, the user first selects the time period for the projection, and identifies the year that excess capacity, if it exists, is anticipated to end. If excess capacity is exhausted within the projection period, the CC/CT market price takes effect in at that point in time. If no new capacity is needed within the projection period, then the market price assumed in the base year is simply escalated over the period of analysis based on a user specified escalation rate.

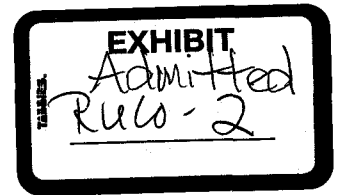
Depending on the market price methodology, selected escalation rates must be entered:

- CC/CT mixed price: escalation rates for Fuel Costs, Capital Costs, and O&M costs.
- Energy and Capacity Charges: escalation rates for the energy and capacity charges.
- Exogenous market price: Escalation rate for the exogenous ¢/kWh market price.

In addition to market price escalation data, escalation rates can be applied to the utility's average retail generation price and its retail sales in the base year.

Once the model calculates the projection of strandable costs, the sum of the strandable costs stream is converted to net present value. In a final important step, an adjustment is made to reflect the net present value of the generation-related regulatory assets not yet in ratebase. The sum of the stream of strandable costs and the potentially strandable regulatory assets, both in terms of net-present value, is the total potential strandable costs.

Based on a series of assumptions about the future costs of fuel, the increase in the market price over time, and the option to consider a transition charge, a full range of strandable cost sensitivities may be examined.



BEFORE THE ARIZONA CORPORATION COMMISSION

**IN THE MATTER OF)
COMPETITION IN THE)
PROVISION OF ELECTRIC)
SERVICES THROUGHOUT)
THE STATE OF ARIZONA)**

DOCKET NO. RE-00000-94-0165

REBUTTAL TESTIMONY OF

DR. RICHARD A. ROSEN

**Submitted on Behalf of
The Residential Utility Consumer Office**

February 4, 1998

Summary of Rebuttal Testimony of Dr. Richard Rosen

This testimony is offered as a rebuttal to direct testimony filed by many parties in Arizona Corporation Commission (ACC) Docket No. U-0000-94-165. Generally, I agreed with many of the policies supported by other parties, especially the points raised by the ACC Staff regarding the need for the use of a retail market price rather than the wholesale market price in the calculation of stranded costs, the need to share positive stranded costs, the usefulness of a price cap, and the need for incentives to ensure the mitigation and reduction of uneconomic costs. However, I disagreed with those parties supporting the use of the Dow Jones Palo Verde Index for estimating market prices, for advocating the securitization of stranded costs, and freezing rates. I disagree that a bottom-up or asset-by-asset approach to computing stranded costs conflicts in any way with a top-down or net system approach. I also disagree with arguments for full recovery of stranded costs based on the existence of a regulatory compact. I counter the argument that stranded cost recovery charges create barriers to exit and entry in competitive markets. I believe that there will be no change in the value of the transmission and distribution system that can be used to mitigate stranded generation costs. Finally, although I do not oppose divestiture, I believe it is an acceptable method for stranded cost recovery only if accompanied by a true-up mechanism based on a net system approach.

Tucson Electric Power Company (TEP) advocates the use of Dow Jones Palo Verde Index (PVI) for estimating market prices. I strongly disagree that the PVI will provide the best estimate of the type of market prices that are necessary for computing stranded costs. The PVI is a short-term spot market wholesale price. The use of a short-term spot market wholesale price for computing stranded costs may unjustifiably increase the magnitude of stranded costs. The market prices that should be used to calculate costs that might become stranded due to retail competition must be the market price for retail generation services. Thus, projections of those retailing costs, which make up what I call the "retail margin," should be added to long-run projections of competitive wholesale prices in order to derive a more accurate market price for retail generation services for computing stranded costs.

I disagree with TEP's position that securitization should be used as a method for stranded cost recovery. Based on my initial estimates of TEP's strandable costs, they are too uncertain for securitization to be a prudent approach for recovering any of these stranded costs. The use of a non-securitized competitive transition charge ("CTC") with opportunity for true-up provides for more flexibility in stranded cost recovery given the inherent uncertainty in estimating stranded costs. Thus, the ACC should not securitize any level of TEP's strandable costs in order to prevent the problem of ratepayers inadvertently over-paying for these costs if market prices turn out to be higher than currently anticipated. Second of all, as I stated in my direct testimony, TEP should not be allowed to recover its stranded costs after January 1, 2003, even if this implies the need to write-off more stranded costs than it otherwise would have to. TEP ratepayers should have to pay only the market price for generation after full-scale retail access begins.

In this rebuttal testimony I demonstrate how, on average, TEP would likely over-collect its stranded costs if a rate freeze were in place. Thus, I oppose TEP's proposal for a rate freeze. I recommend capping the rate, as opposed to freezing rates, for the standard offer generation service at either the generation rate that would have been charged to each customer class if regulation had continued, or at the market price for retail generation services appropriate to that customer class, whichever is lower.

Regulators have always balanced the customer's right to adequate service at reasonable rates with the investor's opportunity to earn a fair return. The notion of risk-sharing is not new—in fact, I describe decisions made by public utility commissions as far back as 1980 which prove that regulators have often allocated the burden of uneconomical excess costs between utility investors and ratepayers. That balancing of ratepayer vs. investor interests does not support the notion of a compact or claims of entitlement to full recovery of prudent investments under the Constitution. Therefore, I disagree with the notion that a "regulatory compact" has existed in the past.

Even though I am strongly in favor of Dr. Rose's arguments in favor of the sharing of stranded costs, I do not agree with Dr. Rose's arguments on behalf of the ACC Staff which attempt to show that any level of the recovery of stranded costs will have a negative impact on the development of a competitive generation market. The existence of a non-bypassable stranded cost recovery charge will not create barriers to exit and entry in a competitive market. After rates are unbundled, all customers in each rate tariff will pay the same stranded cost recovery charge whether or not they stay on the standard offer. As long as all customers pay the same stranded cost recovery charge based on their usage of the distribution system, all generation suppliers including the standard offer providers are on an equal basis. Thus, no barriers to exit or entry can be created by collecting this charge. I discuss self-generation as a possible exception where stranded cost recovery could lead to uneconomic bypass.

I disagree with the statement that a rise in the value of the transmission and distribution system should be used to mitigate stranded costs on the generation side. In a restructured environment, transmission and distribution systems will remain regulated. Therefore, no change in value of the transmission and distribution system will be possible, since there will not be a free market in transmission and distribution ("T&D") services.

Finally, divestiture as a method of stranded cost recovery was raised by several parties in this docket. Although RUCO does not advocate that divestiture of utility generation assets be required, RUCO does not oppose divestiture. However, parties should be aware that a market valuation approach to stranded costs may yield auction, spin-off, or sale prices that are either too low or too high relative to actual long-run market prices for generation at the wholesale level. An artificially low sale price received for generation assets would, of course, increase stranded costs above the level they should be if market prices reflecting a more competitive market were utilized for their determination. Thus, divestiture or market valuation is not necessarily a more accurate way to determine stranded costs than an administrative evaluation approach. From a

consumer protection perspective, divestiture can be an acceptable method for estimating stranded generation costs only if it is accompanied by a true-up mechanism that incorporates a "net system" perspective. A net-system true-up approach under an administrative valuation stranded cost determination method would take the sale price of divested generation assets into account as partial evidence of market price in addition to other data on current and projected prices for retail generation services.

1 Q. ARE YOU THE SAME RICHARD A. ROSEN WHO FILED DIRECT
2 TESTIMONY IN THIS DOCKET?

3 A. Yes, I am.
4

5 Q. DO YOU AGREE WITH MANY OF THE POSITIONS HELD BY OTHER
6 PARTIES IN THIS DOCKET?

7 A. Yes, I generally agree with many of the policies supported by other parties in this
8 docket, especially the points raised by the Arizona Corporation Commission Staff
9 regarding the need to use a retail price rather than the wholesale market price in
10 the calculation of stranded costs, the need to share positive stranded costs, the
11 usefulness of a price cap, and the need for incentives to ensure the mitigation and
12 reduction of uneconomic costs. Therefore, I also agree with Dr. Mark Cooper's
13 belief, stated in his direct testimony on behalf of the Arizona Consumers Council,
14 that there should be a sharing of stranded costs between ratepayers and
15 shareholders, and particularly that ratepayers should not be responsible for more
16 than 50 percent of that recovery. I also agreed with the general line of argument
17 Dr. Cooper raised against the securitization of stranded costs and against the
18 existence of a regulatory compact. Carl Dabelstein's testimony also raised salient
19 arguments supporting the use of the administrative approach for the quantification
20 of stranded costs and the need for a true-up mechanism. Both are positions I
21 support.
22
23

1 **REBUTTAL TO FILINGS OF AFFECTED UTILITIES**

2 Q. WOULD YOU LIKE TO RESPOND TO ANY OF THE TESTIMONY FILED
3 BY AFFECTED UTILITIES IN THIS DOCKET?

4
5 A. Yes, I would like to respond to just a few points regarding the proper stranded
6 cost calculation methodology that were made in TEP's testimony.

7
8 Q. DO YOU HAVE A RESPONSE TO TEP'S COMMENT ON THE USE OF THE
9 DOW JONES PALO VERDE PRICE INDEX AS THE BEST ESTIMATE OF
10 THE MARKET PRICE FOR THE PURPOSE OF COMPUTING STRANDED
11 COSTS?

12 A. Yes, I would like to respond to Mr. Bayless' comment on page 14 of his testimony
13 on behalf of TEP where he states, "TEP proposes using the Dow Jones Palo Verde
14 Price Index ("PVI") as a market price estimate." I strongly disagree that the PVI
15 will provide the best estimate of the type of market prices that are necessary for
16 computing stranded costs. *First, the PVI is a short-term spot market wholesale*
17 *price which reflects the current situation of excess capacity. Therefore, it tends to*
18 *be a low wholesale price and does not reflect the higher prices of long-term*
19 *contracts for firm capacity purchases.*

20 Regarding this very point, on page 15 of his testimony Mr. Bayless was
21 asked, "Shouldn't the market price used for calculating stranded costs include
22 long-run capacity costs?" He replied, "Yes, to the extent that such costs are
23 recovered in the competitive market. Further, as excess capacity is depleted and

1 the market for capacity becomes tighter, the PVI price will more fully reflect
2 capacity costs." This may be true, but it does not change the fact that the PVI
3 price will be a short-term price. A more appropriate estimate of a wholesale
4 market price for power to meet a certain type of load, such as peaking, cycling, or
5 baseload, should be no less than the unit cost of financing, constructing, and
6 operating those plants needed to meet that load in the least-cost way over the long
7 run. Ancillary service costs and the impact of transmission and distribution
8 ("T&D") losses must also be taken into account.

9 The use of a short-term spot market wholesale price for computing
10 stranded costs may, therefore, unjustifiably increase the magnitude of stranded
11 costs. As Dr. Rosenberg, testifying on behalf of Arizonans for Electric Choice and
12 Competition, et al., also stated in his testimony, "Because spot energy prices are
13 typically lower than the prices of other competitive power contracts, the exclusive
14 use of spot energy to measure market prices is likely to increase the magnitude of
15 stranded costs. A spot market wholesale price is not indicative of the price that
16 customers realistically will be able to obtain if they desire intermediate to long-
17 term retail firm service (pages 16-17)."

18
19 Q. WHAT TYPE OF MARKET PRICES DO YOU BELIEVE SHOULD BE USED
20 TO CALCULATE STRANDED COSTS?

21 A. As discussed at length in my direct testimony, a wholesale market price, as
22 advocated by Mr. Bayless, is not the appropriate type of market price for
23 computing stranded costs. Mr. Higgins, testifying on behalf of Arizonans for

1 Electric Choice and Competition, et al., stated, "Components of the average retail
2 market price will include the underlying wholesale price of power (e.g., DJ Palo
3 Verde Index), plus a retail mark-up of perhaps 10 percent." I believe Mr. Higgins
4 is partially correct, but he does not adequately portray the amount and components
5 of the non-wholesale components of the market price for retail generation services.
6 The market prices that should be used to calculate costs that might become
7 stranded due to retail competition must be the market price for retail generation
8 services. Dr. Kenneth Rose, testifying on behalf of the Arizona Corporation
9 Commission, stated on page 19 of his direct testimony, "...Price scenarios must
10 reflect the projection of a retail price that end-use customers will likely see. It
11 should not be based on a projection of wholesale prices that wholesale and other
12 large customers face in the spot market." To use a wholesale market price to
13 calculate a utility's stranded costs significantly underestimates the appropriate
14 market price, and, thus also overestimates strandable costs. (My response assumes
15 that the market price is being compared to the unbundled generation component of
16 required revenues when computing stranded costs, as in a "top-down" approach.)
17 Of course, this same point applies to many other witnesses in this case, such as Mr.
18 Dick Minson, who states that stranded costs should be computed using long-term
19 marginal prices, but who forgets to say that these prices should be retail prices.

20 In addition to the cost of buying power at wholesale, the types of costs that
21 competitive alternative generation suppliers will incur to provide retail generation
22 services fall into the following categories: generation-related customer services,
23 ancillary services, marketing and advertising, generation-related administrative and

1 general services, profits and income taxes on profits, and other taxes. Each type of
2 cost just listed should be reflected in the estimated market price for retail
3 generation services used to compute stranded costs. Each type of cost will be
4 incurred by retail generation suppliers, regardless of whether they provide each and
5 every service from in-house resources or whether they contract out certain
6 services. Thus, projections of these retailing costs, which make up what I call the
7 "retail margin," should be added to projections of competitive wholesale prices in
8 order to derive a more accurate market price for retail generation services for
9 computing stranded costs. (Please see Section 4 on the market price of retail
10 generation services in my direct testimony for a more complete discussion of this
11 issue). Thus, it is the total market price for retail generation services as determined
12 by alternative suppliers to the utilities, not spot wholesale prices such as those in
13 the Dow Jones Palo Verde Index, that will determine the revenue that the existing
14 utilities will be able to earn in the future retail market.

15
16 Q. DO YOU HAVE A RESPONSE TO TEP'S PROPOSAL TO SECURITIZE 75
17 PERCENT OF ITS STRANDED COSTS WITH REPAYMENT OVER 10-15
18 YEARS?

19 A. Yes, I would like to respond to Mr. Bayless' proposal on page 17 of his testimony.
20 He stated, "The Company's proposal requires rates to be fixed at some level to
21 recover stranded costs via the CTC through 2004 and securitization of up to 75
22 percent of stranded costs with repayment over 10-15 years."

1 First of all, I disagree that securitization should be used as a method for
2 stranded cost recovery. Based on my initial estimates of TEP's strandable costs,
3 they are too uncertain for securitization to be a prudent approach for recovering
4 any of these stranded costs. My estimates range from a low of \$257 million to a
5 high of \$770 million in 1998 present value dollars. Securitizing even a portion of
6 the low estimate of \$257 million in strandable costs locks TEP's ratepayers into
7 this recovery mechanism at a fixed level. It could be that even this low estimate
8 will prove too high, and therefore 75 percent of this low level will also prove to be
9 too high. The use of a CTC that is not securitized would enable the utility to cope
10 with changes in the estimates of stranded costs over time due to the true-up
11 process. The use of a non-securitized CTC provides for more flexibility in stranded
12 cost recovery given the inherent uncertainty in estimating stranded costs. Thus,
13 the ACC should not securitize any level of TEP's strandable costs in order to
14 prevent the problem of ratepayers inadvertently over-paying for these costs if
15 market prices turn out to be higher than currently anticipated.

16 Second of all, as I stated in my direct testimony, TEP should not be
17 allowed to recover its stranded costs after January 1, 2003, even if this implies the
18 need to write-off more stranded costs than it otherwise would have to. TEP
19 ratepayers should have to pay only the market price for generation after full-scale
20 retail access begins.

21 Q. DO YOU AGREE WITH TEP'S PROPOSAL FOR A RATE FREEZE?

22 A. No, I do not agree with TEP's proposal for a rate freeze. To again quote Mr.

23 Bayless' comment on page 17 of his testimony, "The Company's proposal requires

1 rates to be fixed at some level to recover stranded costs via the CTC through
2 2004..." I believe that a price cap is more appropriate than a rate freeze, as
3 discussed in my direct testimony. A rate freeze may provide the opportunity for
4 Affected Utilities to make greater profits than are likely under normal ratemaking
5 practices by accelerating the recovery of stranded costs. In fact, my calculations
6 indicate that if TEP had a rate freeze from 1998-2002, they would over-collect
7 their strandable costs by \$268 million in the high market price scenario and under-
8 collect their stranded costs by \$126 million in the low market price scenario in
9 1998 present value dollars.¹ Therefore, on average, TEP would likely over-collect
10 its stranded costs, and thus I oppose a rate freeze. I recommend capping the rate
11 for the standard offer generation service at the lower of the generation rate that
12 would have been charged to each customer class if regulation had continued, or
13 the market price for retail generation services appropriate to that customer class.
14 This approach would provide a much fairer and more objective basis for setting a
15 rate cap during the transition period than just freezing rates at today's level.

16 Q. WHAT IS YOUR POSITION REGARDING THE EXISTENCE OF A
17 REGULATORY COMPACT BETWEEN UTILITY COMPANIES AND
18 REGULATORS OR RATEPAYERS?

¹ This estimation of stranded cost collection in the case of a rate freeze is based on my high and low estimates of stranded costs for TEP (See Exhibit __ (RAR-8), p.1 of my direct testimony). The high market price scenario yielded total stranded costs of \$257 million and the low market price scenario yielded total stranded costs of \$770 million in 1998 present value dollars. The stream of stranded costs between the years 1998-2002, in 1998 present value dollars, yielded \$526 million in stranded cost recovery in the high market price scenario. In the low market price scenario, that stream of stranded costs yielded \$644 million in 1998 present value dollars. The difference between the two defines how much TEP would over- or under-collect in stranded cost recovery.

1 A. First I would like to say that issues regarding the “regulatory compact” involve
2 legal issues, and are, therefore, most appropriately addressed in legal briefs.
3 However, because TEP’s witnesses, Charles Bayless and Daniel Fessler, have
4 addressed these issues at length in their testimony, I will rebut their positions.
5 Please note for the record that I am not an attorney. However, I have testified
6 many times over the past 15 years before public utility commissions all over the
7 U.S. on the issues of the prudence of utility investments, and the sharing of
8 uneconomic utility costs as a policy witness. In fact, my testimony on the sharing
9 of canceled utility plant in Pennsylvania was the basis for the well-known U.S.
10 Supreme Court case *Duquesne Light Co. v. Barasch*.

11 Thus, based on my long experience with these issues, I disagree with the
12 notion that any kind of a “regulatory compact” has existed in the past that goes
13 beyond the state utility code in any way. Arizona utilities claim that state utility
14 commissioners are bound by a long-standing compact which requires that they be
15 assured at the outset that they will recover all investment not previously disallowed
16 as imprudent. Such assurance is required, they claim, on the grounds of
17 constitutional right, fairness and symmetry. Mr. Bayless, on page 6 of his
18 testimony stated, “The operations of public utilities, since shortly after their
19 inception, have been based on the Compact. In Arizona, electric utilities were
20 given a Certificate of Convenience and Necessity and were required to build
21 facilities to serve everyone in their respective service territories and were allowed
22 the opportunity to earn a reasonable return on their investment.” But the argument
23 supporting the existence of a regulatory compact is not sound. Dr. Kenneth Rose,

1 testifying on behalf of the Arizona Corporation Commission, stated in his direct
2 testimony,

3 "The Rules and the method of stranded cost recovery that is
4 suggested elsewhere in this testimony do not break or violate the
5 regulatory compact, but rather redefine and modify it as a matter of
6 state public policy during a transition period to greater competition
7 in the electric industry. ...the opportunity to recover costs and earn
8 a reasonable return on and if its investments still exists under the
9 Rules. We must be clear that the social compact is not now, nor has
10 it ever been a contract guaranteeing the utility a perpetual
11 monopoly, freedom from competition or full cost recovery. No
12 argument can be made that there is now or was in the past a
13 contract obliging the people of Arizona to pay for uneconomic
14 costs (pages 2-3)."

15
16
17 I agree with Dr. Rose.

18

19 Q. HAVE OTHER UTILITY EXPERTS REJECTED THE EXISTENCE OF THE
20 REGULATORY COMPACT?

21 A. Yes, many utility experts reject the idea that there has ever been a regulatory
22 compact that dictates 100 percent recovery of stranded costs. For example, in
23 testimony before the State of New Jersey Office of Administrative Law, ex-PUC
24 Commissioner Peter Bradford stated,

25
26 I have found no discussion of such a compact before the early
27 1980s. ...I make the following points (regarding the notion of a
28 regulatory compact):
29 1) Courts have never endorsed the notion of a compact.
30 2) Courts have rejected the argument that if an investment is
31 prudent, the shareholders are entitled to full recovery.
32 3) The franchises created early in the industry's history did not
33 establish an ongoing regulatory compact; in fact, they were
34 displaced for most purposes by regulation precisely to avoid the

1 contract-like inflexibility which the utilities now seek to attribute to
2 regulation itself.

3 4) The concept of "regulatory compact" or "regulatory bargain"
4 plays no role in the considerable economic literature on regulation.

5 5) State commissions today are rejecting the notion of a compact.²
6

7 The review of relevant regulatory literature performed by Mr. Bradford
8 indeed found that prior to the 1980s, there was no discussion of a regulatory
9 compact. He explains how before that time, he found only general arrangements
10 that varied from state to state and from time to time, arrangements that might give
11 rise to investor hopes but not to the constitutionally protected claims commonly
12 asserted by utilities in restructuring hearings.
13

14 Q. IS THERE ANY HISTORICAL PRECEDENT FOR THE POSITION THAT
15 YOU ADVOCATE IN FAVOR OF RISK-SHARING BETWEEN
16 RATEPAYERS AND STOCKHOLDERS?

17 A. Yes, there is. We should not forget that risk-sharing of uneconomical generating
18 capacity and investments is not a new issue. Two fairly old regulatory decisions —
19 the Kansas Corporation Commission-Wolf Creek case (1985) and Massachusetts
20 Department of Public Utilities-Millstone 3 case (1986) — illustrated that many
21 regulatory commission believed that investments in new capacity must be
22 economically justified and that risk-sharing must apply to the portion of those
23 investments deemed to be uneconomic. (Please refer to *Risk Sharing and the*

² Direct Testimony of Peter A. Bradford, previously Chairman of the Maine and New York public utility commissions, before the State of New Jersey Office of Administrative Law. BPU Docket No. EO97070462, OAL Docket No. PUC-7347-97, BPU Docket No. EO97070461 and OAL Docket No. PUC-7348-97. Filed November 26, 1997. Pages 5-7.

1 *'Used and Useful' Criterion in Utility Ratemaking* by Dr. Stephen Bernow and
2 myself, attached as Exhibit RAR-13, for a more lengthy discussion of this issue.)

3 In particular, the Massachusetts Department of Public Utilities (DPU), in
4 Docket No. 85-270, most directly applied the approach of measuring economic
5 value as the appropriate test of when a utility investment is "used and useful," and
6 accepted the need for risk-sharing in the regulatory treatment of excess costs in
7 their rate treatment of Millstone 3. With respect to the "used and useful" standard,
8 the DPU stated,

9 The used and useful standard requires the Department to determine
10 whether the utility investment is needed and economically desirable.
11 Need for a new electric utility production plant is established if it
12 can either be shown that the investment in question can provide
13 either capacity or energy which is required by the utility, at a new
14 cost which is lower than the cost of the capacity and/or energy
15 which it displaces. Once need for capacity and/or energy savings
16 has been established, the Department must then determine the
17 extent to which an investment is useful and thus the extent to which
18 a return should be allowed on the investment. Even if it could be
19 shown that a utility had an immediate need for additional capacity,
20 such a demonstration in and of itself would not be sufficient to
21 justify a particular generating unit; the Company still must
22 demonstrate that the generating unit it had constructed to meet
23 capacity need was the most cost-effective (Order, pp. 64-65).

24 In its order, the DPU established the economic value of the unit by
25
26 calculating the estimated cumulative net present value of revenue requirements
27 associated with the least-cost alternative generation expansion plan that would
28 have been followed had Millstone 3 not been built. The analysis indicated that the
29 revenue requirements of the optimum alternative generation scenario was 24
30 percent lower than the present value of revenue requirements that resulted because

1 Millstone 3 was built. The result of this analysis was a significant sharing of the
2 excess costs between ratepayers and investors.

3 Similarly, in Docket Nos. 142,098-U and 142,099-U, the Kansas
4 Corporation Commission examined the requests of Kansas City Gas and Electric
5 and Kansas City Power and Light to include in their rate base their investment in
6 the Wolf Creek nuclear plant. The Kansas Commission implemented the traditional
7 prudence test by determining that a portion of the construction cost was
8 "inefficiently and imprudently incurred." Secondly, over and above this imprudency
9 disallowance, the Kansas Commission identified a portion of Wolf Creek as excess
10 capacity, finding that "reserves in excess of 20 percent should be justified from an
11 economic perspective." Finally, the Commission accepted the concept of economic
12 risk-sharing I advocated in the case.

13
14 Q. WERE THESE TWO DECISIONS THE FIRST OR PRECEDENT-SETTING
15 DECISIONS ON RISK-SHARING IN CASES OF EXCESS CAPACITY THAT
16 LED TO THE EXISTENCE OF UNECONOMIC COSTS?

17 A. No, there were several regulatory commission decisions made previously which
18 also supported risk-sharing. Back in 1980, the Pennsylvania Commission, in a
19 decision involving the Philadelphia Electric Company, found the Company in
20 possession of excess capacity (Docket No. 79060865). The Commission found
21 that the excess capacity was not due to errors or mismanagement on the part of the
22 Company. Rather, unanticipated events such as lower than expected demand
23 growth had caused some of the Company's generation capacity to become

1 "excess," as new generating units were added. The Commission adjusted the
2 Company's rates to apportion some of the cost of the excess capacity to investors
3 in the Company. In discussing this decision in a speech before the Pennsylvania
4 Bar Association, Chairman Shanaman of the Pennsylvania Utility Commission
5 stated:

6 Prior to making its rate base adjustment, the Commission made the
7 explicit finding that the burden of excessive plant investment was
8 not the fault of Philadelphia Electric or its investors, but neither was
9 it the fault of the ratepayers. We found that, under the
10 circumstances, there must be some sharing of the risk associated
11 with maintaining plants on-line. [Emphasis in the original.]
12

13 Another decision took place in Kentucky in 1983, when the Kentucky
14 Public Service Commission removed 50 percent of a new water treatment plant
15 from the ratebase of the Kentucky-American Water Co. (Case No. 8571). The
16 Commission found that excess capacity of water treatment facilities existed on the
17 Kentucky-American system, and that an equal sharing of the risk (50/50) was
18 appropriate under the circumstances.

19 The four decisions mentioned above illustrate that the rate treatment of that
20 portion of the investment which is found to be uneconomical, i.e. not "used and
21 useful," has most equitably been handled through the application of the prudent
22 investment test in combination with "risk sharing." This is the approach regulators
23 have used to allocate the burden of uneconomical or excess costs between the
24 utility's investors and ratepayers in reasonable proportions, based on the facts
25 responsible for the existence of the costs and the circumstances under which they
26 were incurred, thereby balancing ratepayer vs. investor interests.

1 Q. COULD YOU ELABORATE ON WHY YOU BELIEVE THAT THE
2 BALANCE STRUCK BY REGULATORS BETWEEN FAIR RATEMAKING
3 AND INVESTORS' OPPORTUNITY TO EARN A FAIR RATE OF RETURN
4 DOES NOT NECESSITATE THE EXISTENCE OF A REGULATORY
5 COMPACT?

6 A. Regulators have always balanced the customer's right to adequate service at
7 reasonable rates with allowing the investors' an opportunity to earn a fair return.
8 That balancing of ratepayer vs. investor interests does not support the notion of a
9 compact or claims of entitlement to full recovery of prudent investments under the
10 Constitution. Therefore, I disagree with Mr. Bayless's comment on page 6 of his
11 direct testimony that,

12 " ...the continued existence of the Compact (is shown) as earnings
13 are limited on prudent investments to a regulated rate of return. If a
14 utility builds a plant or transmission line which operates at a cost far
15 below the current market, the company is only allowed to earn a
16 regulated return on its actual cost. The utility is never allowed to
17 charge a market rate and hit a "home run" for investors as non-
18 regulated entities do. ...The requirement for TEP to sell its
19 products at a below-market price, in my view, constitutes an
20 unconstitutional "taking" for a public purpose without just
21 compensation. In the past, the Company did not, however,
22 complain about the unconstitutional taking."

23
24 I also disagree with the assertion of a legal entitlement to recover stranded
25 costs from ratepayers. Daniel Fessler, testifying on behalf of TEP, commented on
26 page 26 of his direct testimony that,

27 ...It is fully appropriate that existing ratepayers on whose behalf the
28 assets were constructed and liabilities assumed should bear the
29 costs. I support the principle that net uneconomic generation assets,
30 above-market purchase power contract obligations and regulatory
31 assets remain the obligation of ratepayers and that restructuring not

1 be used as an opportunity to attempt to shift them to utility
2 shareholders.

3
4 Assuming that ratepayers, on whose behalf the assets were constructed,
5 should bear the full costs of those assets under all conditions is far too simplistic.
6 Some of the uneconomic costs on a utility's system that will become stranded
7 costs under competition are due to bad or questionable management decisions
8 and/or poor resource planning practices. Prudency approvals should not
9 necessarily protect utilities from later having to write-off portions of their
10 uneconomic costs if they do not turn out to be used and useful. Even if decisions
11 to acquire generation-related assets were deemed prudent at the time, there is
12 ample justification in regulatory theory for sharing stranded costs between utility
13 stockholders and ratepayers now, given that there always has been some risk that
14 management decisions were not the most economically efficient. Kevin Higgins,
15 testifying on behalf of Arizonans for Electric Choice and Competition, et al., stated
16 in his rebuttal testimony in this docket that,

17 Mr. Bayless' view (on the existence and rationale of a regulatory
18 compact) is unreasonable. The regulatory environment in which
19 TEP has heretofore operated does not convey a blanket
20 responsibility upon customers to bear the costs of TEP generation
21 for up to thirty years after the introduction of competition. His
22 argument presumes that deregulation of generation service is a one-
23 way street: good for consumers, bad for investors. It ignores the
24 fact that deregulation of generation prices will mean that investors
25 will have opportunities over the long-run to earn above a regulated
26 return...(page 2)"

27
28 I agree with Mr. Higgins that Mr. Bayless' view is unreasonable. Mr.
29 Higgins raises the important point that deregulation of generation services may

1 increase opportunities for shareholders to realize greater rates of return on their
2 investments.

3
4 **REBUTTAL TO FILINGS OF OTHER PARTIES**

5 Q. WOULD YOU LIKE TO RESPOND TO ANY OF THE TESTIMONY FILED
6 BY NON-UTILITIES IN THIS DOCKET?

7 A. Yes, I would also like to respond to some of the testimony filed by non-utilities by
8 topic or issue, as I have done above for the affected utilities.

9
10 Q. DO YOU SUPPORT MOST OF DR. ROSE'S ARGUMENTS IN FAVOR OF
11 THE NEED TO SHARE STRANDED COSTS BETWEEN RATEPAYERS
12 AND STOCKHOLDERS?

13 A. Yes, I support most of Dr. Rose's arguments in favor of the need to share stranded
14 costs, but I only support sharing stranded costs if they are positive. If a negative
15 stranded cost recovery charge were to be put into place for APS and SRP, then I
16 would not be in favor of sharing stranded costs between ratepayers and
17 stockholders. In such a case, the ratepayers should get the full benefit of the
18 negative stranded cost recovery charge. The reason for my position is the inherent
19 and appropriate asymmetry in the regulation of electric utilities in the past, as Dr.
20 Rose describes on pages 5-6 of his testimony. Under traditional cost-of-service
21 regulation, utilities should be allowed a maximum rate of return on equity which
22 includes a risk premium to cover various business risks. They should not be
23 allowed to recover extraordinary profits above and beyond a reasonable allowed

1 return on equity if they have negative stranded costs, and if retail competition is
2 implemented in Arizona. All the benefits of the investments in power plants that
3 ratepayers have funded in the past should be flowed through to ratepayers in the
4 future to the extent that negative stranded costs exist. That is because, by
5 definition, the calculation of negative stranded costs assumes a reasonable allowed
6 rate of return on utility assets as a baseline.

7 One particularly strong reason for sharing stranded costs cited by Dr. Rose,
8 aside from the basic equity in doing so, is that sharing will provide a very strong
9 incentive for utilities to mitigate stranded costs. I, too, have often cited this
10 advantage of sharing in my written testimony and reports about stranded costs.
11 Sharing provides a strong incentive to mitigate stranded costs because the utility
12 will save the proportion of the sharing that it would otherwise have to pay for each
13 dollar of stranded costs actually mitigated. For example, if there were a 50/50
14 percent sharing of stranded costs, the utility would save \$0.50 of each dollar
15 actually mitigated by not having to write-off that \$0.50 against its profits.

16 Q. DO YOU ALSO AGREE WITH DR. ROSE THAT ANY LEVEL OF
17 RECOVERY OF UNECONOMIC OR STRANDED COSTS FROM
18 CUSTOMERS WILL HAVE A "NEGATIVE IMPACT ON THE
19 DEVELOPMENT OF A COMPETITIVE MARKET," AS DR. ROSE STATES
20 ON PAGE 9 OF HIS TESTIMONY?

21 A. No. Even though I am strongly in agreement with Dr. Rose's arguments in favor
22 of the sharing of stranded costs, I do not agree with Dr. Rose's arguments which
23 attempt to show that any level of the recovery of stranded costs will have a

1 negative impact on the development of a competitive generation market, with one
2 exception. The one exception is self-generation, which in fact, is the one issue that
3 Dr. Rose dismisses as a possible exception, prematurely in my view. I believe that
4 the possibility of uneconomic bypass via the use of self-generation as discussed by
5 Dr. Rose on pages 10-12 of his testimony is the one case in which the recovery of
6 stranded costs, even through a non-bypassable wires charge, is a problem.

7 The reason that I believe that uneconomic bypass could be a problem is
8 that a so-called "non-bypassable" wires charge is bypassable in one and only one
9 way, namely if a customer decides to self-generate on-site and not use the T&D
10 wires for delivering a certain amount of power to the site. That means that a high
11 stranded cost recovery charge would work as an incentive to self-generate in order
12 to avoid paying the stranded cost recovery charge. If uneconomic bypass occurs,
13 namely if self-generation has higher marginal costs than to continue buying from
14 the utility, then this would lead to a less than perfectly competitive generation
15 market, by definition. Of course, avoiding paying any transmission and distribution
16 charges is also an incentive to self-generate, but this factor has always existed
17 independently of a stranded cost recovery charge.

18 Perhaps Dr. Rose dismisses the significance of the incremental impact of
19 stranded cost recovery on the likelihood of uneconomic bypass through self-
20 generation because he realizes there is already a strong incentive for large
21 customers to self-generate in order to avoid T&D system charges. However, in
22 my view there is nothing a public utility commission can or should do to try to
23 prevent uneconomic bypass due to self-generation. It is an issue that has always

1 confronted the regulatory world, and it is an issue that will continue to exist under
2 retail competition. Little has changed with regard to this issue, and I believe we
3 need to live with this limited imperfection in generation markets due to the need to
4 regulate the T&D system.

5
6 Q. WITH THE EXCEPTION OF SELF-GENERATION, WHY DON'T YOU
7 AGREE WITH DR. ROSE THAT THE RECOVERY OF A STRANDED COST
8 CHARGE AS A NON-BYPASSABLE WIRES CHARGE CAN CREATE
9 BARRIERS TO ENTRY AND EXIT IN THE GENERATION MARKET?

10 A. The reason I disagree with Dr. Rose that the existence of a non-bypassable
11 stranded cost recovery charge can create barriers to exit and entry is that Dr. Rose
12 seems to have mis-characterized the structure of rates for the standard offer
13 service that should be established after unbundling occurs. He does not seem to
14 recognize that after rates are unbundled, all customers in each rate tariff should pay
15 the same stranded cost recovery charge whether or not they stay on the standard
16 offer. This is what makes the stranded cost recovery charge non-bypassable. As
17 long as all customers pay the same stranded cost recovery charge based on their
18 usage of the distribution (or transmission) system, all generation suppliers,
19 including the standard offer providers, are on an exactly equal basis. Thus, no
20 barriers to exit or entry can be created by collecting this charge, no matter how big
21 it is.

22 Dr. Rose may have come to the wrong conclusion about barriers to entry
23 and exit because his illustration of the problem discussed on lines 18-27 of page 11

1 of his testimony has a critical flaw. In this example, Dr. Rose seems to forget that,
2 according to his example, once rates are unbundled for all customers, including
3 those in the standard offer, the customer who is paying the utility's marginal cost of
4 3.5 cents per kWh will also have to pay the uneconomic cost charge of 2.0 cents
5 per kWh, for a total of 5.5 cents per kWh. This implies that this customer will
6 choose the alternative supplier's power at 4.5 cents per kWh, which, indeed, has
7 the lowest marginal costs. Thus, under the conditions discussed, there will be no
8 uneconomic bypass, the generation market will be competitive, and there will be
9 no barrier to entry for new generation owners into the market due to the collection
10 of stranded costs.

11

12 Q. DOES DR. ROSE'S DISCUSSION OF STATIC VS. DYNAMIC EFFICIENCY
13 CHANGE YOUR CONCLUSIONS IN ANY WAY?

14 A. No. Dr. Rose's rather lengthy discussion of static vs. dynamic efficiency does not
15 change my conclusion that self-generation aside, the collection of a properly
16 structured, non-bypassable, stranded cost recovery wires charge will not impede
17 the economic efficiency of the generation market. This is true whether the
18 stranded cost recovery charge is positive or negative. The basic reason for this
19 conclusion is that any charges included as part of the regulated T&D rates of the
20 utility do not impact on the efficiency of the unregulated markets, as long as
21 similarly situated customers have to pay similar T&D and stranded cost rates.
22 Whether or not the T&D and stranded cost recovery rates are fair or are properly
23 structured is another issue entirely.

1

2 Q. DO YOU AGREE WITH THE STATEMENT IN DR. COYLE'S TESTIMONY,
3 ON BEHALF OF THE CITY OF TUCSON, THAT A RISE IN VALUE OF THE
4 TRANSMISSION AND DISTRIBUTION SYSTEM DUE TO THE
5 EXISTENCE OF RETAIL COMPETITION SHOULD BE USED TO
6 MITIGATE STRANDED COSTS ON THE GENERATION SIDE?

7 A. No, I do not agree with this statement because I do not believe that it makes sense
8 to say that the value of the T&D system will change due to restructuring. Dr.
9 Coyle stated:

10 Restructuring changes the value of the generation assets, and the
11 change is generally assumed to be downward. ...Restructuring
12 changes, at the same time, the value of the transmission system and,
13 separately, the value of the distribution system. Both these changes
14 we can be confident will be an increase in value.
15

16 Dr. Coyle attributes the increase in value to a drop in the cost of capital for
17 transmission and distribution, and less risk on the part of investors. In the
18 deregulated environment, generation is unbundled from transmission and
19 distribution, and the different returns on equity become apparent by the rate of
20 return on equity required by the market. But in a restructured environment,
21 transmission and distribution systems will remain regulated. Thus, even if the
22 required rate of return on equity for the T&D system decreases due to
23 restructuring, no change in value of the transmission and distribution system will
24 be possible, since there will not be a free market in T&D services. The "value" of
25 the T&D system could only increase if the return on equity decreased and the total
26 revenues from the T&D rates stayed roughly the same. However, since no rise in

1 the value of the T&D system will occur due to continued regulation, I can not
2 agree with Dr. Coyle's statement that "the increase in value (of the T&D system)
3 should be used to mitigate stranded costs..." I do, however, agree that the return
4 on equity may be lower due to a difference in risk, which could lower the revenue
5 requirement for T&D services. Therefore, I conclude that transmission and
6 distribution rates may actually be lower in the future due to restructuring than they
7 would have been otherwise. This would be an indirect benefit for ratepayers of
8 restructuring, and one which would indirectly help to mitigate or reduce the net
9 impact of stranded cost recovery on ratepayers.

10

11 Q. IS DIVESTITURE AN APPROPRIATE METHOD FOR ESTIMATING
12 STRANDED GENERATION COSTS, AS SUGGESTED BY DR. ALAN
13 ROSENBERG AND MS. MONA PETROCHKO?

14 A. RUCO does not advocate that divestiture of utility generation assets be required,
15 though RUCO does not oppose divestiture. However, parties in this docket should
16 be aware that a market valuation or divestiture-based approach to determining
17 stranded costs may yield auction, spin-off, or sale prices that are either too low or
18 too high relative to actual long-run market prices for generation in a truly
19 competitive wholesale market. A low sale price received for generation assets
20 would, of course, increase stranded costs if this sale price were used as the sole
21 basis for their determination. Divestiture or market valuation is therefore not
22 necessarily a more accurate way to determine stranded costs than an administrative
23 evaluation approach. That is why I disagree with Alan Rosenberg's statement on

1 page 38 of his direct testimony on behalf of Arizonans for Electric Choice and
2 Competition where he states, "...market based approaches for determining
3 stranded cost are superior to administrative ones, with divestiture being the
4 optimal method."

5 Divestiture does not ensure that retail customers will not be overcharged
6 for stranded costs, in part because market prices are likely to be volatile. If the
7 prices at which generation assets are sold are below the sale prices that a truly
8 competitive market would yield, a utility's stranded costs will be directly affected.
9 If the ACC were to mandate that divestiture in Arizona occur quickly, the
10 regional generation asset market would be flooded, and bidders for the assets
11 would likely see an increase in their bargaining power to obtain generation assets
12 at below competitive market sale prices. However, in the long run, the new owners
13 of the generation assets would presumably sell their output at full competitive
14 market prices. They would not sell their output at below-market prices just
15 because they initially bought the assets at below-market prices. Therefore, in this
16 scenario, consumers would end up paying more than they should in stranded cost
17 recovery changes while not experiencing any compensating reduction in market
18 prices for generation. They would pay twice for some stranded costs, an
19 unacceptable result.

20
21 Q. WHAT SHOULD THE RELATIONSHIP BE BETWEEN THE SALE PRICE
22 DUE TO DIVESTITURE AND STRANDED COSTS RECOVERY?

1 A. From a consumer protection perspective, divestiture can be an acceptable method
2 for initially estimating stranded generation costs only if the recovery process
3 includes a true-up mechanism. Furthermore, any reasonable true-up methodology
4 must be done on a "net system" basis, whereby generating resources having
5 negative strandable costs are netted against generating resources which have
6 positive stranded costs. This would be possible if stranded costs were determined
7 using an administrative net-system valuation approach which took the sale price
8 due to divestiture into account as partial evidence in determining a competitive
9 market price. (Please refer to page 23 of my direct testimony for more explanation
10 of this point.) I prefer the net system approach as opposed to the asset-by-asset
11 approach because the net system approach calculates the stranded costs of a
12 utility's whole system. It is by far more difficult to do this on an asset-by-asset
13 basis. Following an administrative net-system valuation stranded cost
14 determination, a utility may voluntarily divest itself of generation assets.
15 Regulators could then true-up initial stranded cost estimates to reflect actual
16 market prices for generation assets, actual retail market prices for generation
17 services, as well as forecasts of the future retail market prices. Until a fully
18 competitive and mature generation asset market develops, the asset sale prices
19 should not be relied upon as the sole indicator of market value for purposes of
20 calculating stranded costs simply because sale prices currently appear to be highly
21 volatile, and may tend to be too low. If a true-up mechanism is adopted by the
22 ACC based on actual market prices, at least through 2002 as I have recommended,
23 then divestiture could occur at the risk of the utility as to whether or not the sale

1 price was reasonable. In this way, ratepayers would be protected from the risk of
2 over-paying stranded costs.

3
4 Q. DO YOU AGREE WITH BETTY PRUITT'S COMMENT, IN HER DIRECT
5 TESTIMONY ON BEHALF OF THE ARIZONA COMMUNITY ACTION
6 ASSOCIATION, THAT "ONLY THOSE CUSTOMERS IN THE
7 COMPETITIVE MARKET SHOULD PAY STRANDED COSTS, SINCE
8 CAPTIVE CUSTOMERS ARE ALREADY PAYING THESE COSTS AND
9 SHOULD NOT BE SUBJECT TO DOUBLE DIPPING?"

10 A. Generally, I agree with the gist of her comment that ratepayers never be required
11 to pay twice for stranded costs. However, I do wish to clarify her point that only
12 customers in the competitive market should pay stranded costs. First, for
13 competition to occur most efficiently, all utility tariffs should be unbundled so that
14 all customers of retail generation services, regardless of whether they have a
15 competitive supplier or stay on standard offer service, contribute equally (within
16 each tariff) to stranded cost recovery. This is best accomplished through a non-
17 bypassable, nondiscriminatory wires charge which ties the collection of stranded
18 generation costs to the continued use of transmission or distribution service, as I
19 have discussed previously.

20 Utilities must, then, estimate their potentially strandable costs as part of the
21 unbundling process for the purpose of establishing the stranded cost recovery
22 mechanism. The standard offer rate for those customers who stay with their
23 default supplier should be set to approximate the retail market price for generation

1 services, plus a stranded cost recovery charge, plus the cost of transmission and
2 distribution service. This approach to unbundling, which I also recommended in
3 my direct testimony, will imply that customers on the standard offer service and
4 customers who purchase from alternative suppliers will both pay the same stranded
5 cost recovery charge. The same market price assumptions used to estimate
6 stranded costs should be used to determine the standard offer rate. In this way,
7 customers on default service will not be in danger of paying twice for stranded cost
8 recovery, and customers will not be penalized for seeking retail generation services
9 from alternative suppliers. Ms. Pruitt's point, I believe, was just to argue that in
10 the event that the current rate were to be used as the rate for the standard offer as
11 allowed by the current version of the restructuring Rules, the stranded cost
12 recovery charge should not be added to the current rates.

13
14 Q. DO YOU AGREE WITH BETTY PRUITT'S COMMENT THAT "A TRUE-UP
15 MECHANISM IS ACCEPTABLE ONLY IF IT IS LIMITED TO BEING
16 DOWNWARDLY FLEXIBLE (DIRECT TESTIMONY, PAGE 1)?"

17 A. No, I disagree. The point of the true-up mechanism is to ensure maximum
18 flexibility and accuracy in determining the amount of stranded costs that ratepayers
19 must pay. If stranded costs were set at a capped level, the true-up mechanism
20 would no longer be fully adjustable, and therefore estimates of stranded costs
21 made in this modified true-up process would not reflect actual market prices. Once
22 stranded costs have been calculated accurately and a percentage of sharing
23 between ratepayers and stockholders has been decided on, the flexibility of the

1 true-up mechanism both upwards and downwards must be maintained for fairness
2 and equity towards both ratepayers and stockholders. A “downward only” flexible
3 true-up mechanism should not be used as a second mechanism for implicitly
4 accomplishing a sharing of stranded costs. Instead, the degree of sharing should
5 be determined and implemented by the ACC explicitly.

6
7 Q. IN RESPONDING TO ISSUE NO. 3 ON PAGE 3 OF HER TESTIMONY, MS.
8 PRUITT STATES THAT “ACAA RECOMMENDS THAT THE BOTTOM-UP,
9 ASSET BY ASSET APPROACH BE USED” FOR COMPUTING STRANDED
10 COSTS. DO YOU AGREE?

11 A. I do not oppose using an asset-by-asset approach to computing stranded costs, as
12 long as such an approach is made entirely consistent with the administrative “top-
13 down,” or differential revenue requirements approach, that I recommended be used
14 by the ACC in my direct testimony. I believe that Ms. Pruitt’s discussion of these
15 two approaches for computing stranded costs on page 3 of her testimony is
16 somewhat over-simplified, however and I do not agree with her when she says
17 “top-down, revenue lost methods should not be used.” (page 3).

18 One reason why I disagree with her criticism of top-down administratively
19 determined calculations of avoided costs is that she is wrong in concluding that
20 “they do poorly in estimating the amount of stranded costs if utilities lose sales.”
21 In fact, the strandable costs or uneconomic costs of utility generation resources
22 exist whether or not utilities lose sales due to retail competition. It is only through
23 losing sales that these strandable costs actually may become stranded, as I discuss

1 in my direct testimony. Ms. Pruitt does not acknowledge that important
2 distinction in her testimony.

3 Secondly, the administrative "top-down" approach to computing strandable
4 costs is so valuable precisely because it provides the quick means for computing a
5 "control total" for strandable costs. Namely, it yields very directly a total value for
6 all of a utility's strandable costs on a net system basis taking all generation
7 resources and generation-related costs, assets, and liabilities into account. If a
8 "bottom-up" asset-by-asset approach to valuing strandable costs does not yield the
9 same total once other generation-related assets and liabilities are added in, then a
10 mistake has been made. This is because the total net system strandable costs for a
11 utility must equal the sum of the strandable costs for all of its generating assets, by
12 definition. Thus, if done correctly, there is no contradiction or conflict at all
13 between a top-down methodology and a bottom-up methodology for computing
14 strandable costs.

15
16 Q. MS. PRUITT ALSO RECOMMENDS THAT ONLY THOSE COSTS
17 INCURRED BY UTILITIES PRIOR TO DECEMBER 1996 SHOULD BE
18 CONSIDERED FOR STRANDED COST RECOVERY. DO YOU AGREE?

19 A. Yes, I do agree with Ms. Pruitt if by "costs incurred prior to that time" (page 4)
20 she means decisions to invest in new generating assets or decisions to sign
21 purchased power contracts prior to December 1996. In contrast, I do not agree
22 with her recommendation if taken literally that utilities should not be able to
23 recover as stranded costs any costs incurred after December 1996. This is because

1 the calculation of stranded costs needs to be made over a long time period, and
2 many, if not most, of the costs during this time period like fuel and O&M expenses
3 have yet to be incurred. Thus, unless no stranded cost recovery is allowed, some
4 future costs will necessarily be part of any recovery of stranded costs.

5 Again, what I agree with is what I believe Ms. Pruitt meant to say, which
6 was that a utility should be held 100 percent responsible for any strandable costs
7 that resulted from any investment or contracting decisions made after December
8 1996.

9
10 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

11 A. Yes, it does.

RISK SHARING AND THE 'USED AND USEFUL'
CRITERION IN UTILITY RATEMAKING

Dr. Stephen Bernow

Dr. Richard Rosen

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Energy Systems Research Group
120 Milk Street
Boston, Mass. 02109
617-426-5844

I. INTRODUCTION

The fact that public utility investments can involve substantial economic risks has been discussed extensively in the financial press and in the utility regulatory literature over the last decade. This discussion has been stimulated by the economically disastrous consequences of many utility investments that have been made over this time period.

Probably the most prominent examples of economically risky investments within the electric utility industry have been those made in nuclear power plants, many of which have ultimately been either cancelled after incurring substantial costs or completed at costs several times above their initial budget. In these situations, regulators have been faced with the problem of determining how the costs associated with these new facilities should be treated for rate making purposes. However, application of the traditional "used and useful" and "prudence" tests have proven to be difficult and controversial, due in part to the lack of precise definitions of, and measures for, these tests, and in part to the potentially serious financial implications for the utility associated with their application.

The common position of utility management with respect to investments in new capacity has been, and continues to be, that unless an investment is proven to have been imprudent, traditional ratemaking procedures should be followed. According to this perspective, a utility should be given a return of, and on, prudently made investments, so long as they are "used and useful" which, in its typical application, has meant completed and operating. This implies that ratepayers should be responsible for one-hundred percent of the costs that result from a prudent investment, no matter how uneconomical it may be. Historically, most public utility commission rate orders have reflected the position of utility management in this regard.

Those representing the interests of electricity consumers have begun to present an opposing viewpoint in an attempt to obtain more equitable and appropriate rate treatment for uneconomical investments. These groups have argued convincingly that stockholders must share in the financial risks deriving from investments made by utility management, but until recently they have been less than successful in having commission orders reflect this position. Part of the reason for this lack of success has been the absence of a single and consistent methodological framework for determining what costs are unreasonable, and how such costs should be shared between ratepayers and stockholders.

Over the past several years Energy Systems Research Group (ESRG) has developed and presented a functional definition of the "used and useful" criterion which is structured to allow one to

assess the economic usefulness (or value) of an investment in new capacity. This approach permits a determination of that portion of an investment which is "used and useful" and, correspondingly, that portion which embodies "excess costs". In addition, ESRG has advocated using the concept of risk-sharing for determining the appropriate rate treatment of the excess costs associated with such facilities. Others, particularly the Massachusetts DPU, have developed and proposed similar approaches, but ESRG witnesses have presented this methodology most extensively in utility hearings throughout the U.S.

This article describes ESRG's approach to the "used and useful" test as applied to investments in new capacity, and to the use of risk-sharing in determining the rate treatment of such investments. It describes how these approaches both subsume and retain the traditional prudent investment test. It also describes recent cases where this approach has been implicitly or explicitly adopted in commission orders.

II. CAPACITY PLANNING OBJECTIVES

In deciding whether or not to construct new capacity, utility management must evaluate and choose between various alternatives - e.g. purchasing versus building capacity, installing peaking versus base-load units, selecting coal versus nuclear capacity. In general, this involves the development of a plan which embodies a mix of both supply and demand-side options characterized by their magnitude, type, and timing. In this selection process, the planners must balance between three sometimes conflicting objectives, and choose the alternatives which best satisfies all three - i.e. the alternative that will result in a reliable, economic and flexible generation plan.

To meet system reliability requirements the utility must have sufficient capacity in place to serve firm peak demand as loads grow. Guided by forecasts of peak demand, capacity additions are planned and constructed so that adequate capacity will be available at the appropriate time to ensure reliable service. The level of capacity required for adequate reliability must be greater than firm peak demand in order for the utility to satisfy this demand when generating units suffer outages, either forced or planned. This reliability requirement is usually referred to as a required "reserve margin" and is measured in terms of the percentage by which generating capacity exceeds firm peak demand. Required reserve margins vary according to the characteristics of specific utility systems and their degree of interconnection with neighboring systems, but are generally in the range of 15 to 20 percent.

From the standpoint of meeting reliability requirements alone, it would be appropriate for a utility to simply build

peaking facilities such as combustion turbines or small oil/gas steam-electric plants. Such plants could be built quickly in response to load growth, and could provide quick response to hourly load variation with relatively low forced outage rates. These plants typically have low capital costs and high operating costs.

A system composed solely of such peaking units, however, would not enable the utility to satisfy its second major planning objective, i.e. to generate electricity in an economical manner over the long term. To meet that objective the generation mix must also include large base-load plants which take longer to place into operation and which are less reliable. Compared to peaking units these plants have higher capital costs but much lower operating costs, so that their total costs per unit of output are typically lower. Of course, these capital intensive base-load plants may require many years before the savings from their lower operating costs outweigh their higher initial capital costs, i.e. before cumulative net economic benefits are achieved. For this reason choosing the appropriate mix of peaking and base-load plants to achieve an optimum balance between system reliability and generation economics requires a long-term perspective.

Given the many factors which can change over the long term, for example between the initial justification of a new base-load plant and its commercial operation, flexibility becomes an important third planning objective of an optimum generation expansion plan. Many factors, such as capital or operating costs which have significantly exceeded planning budgets, or the unexpected availability of less expensive power from other sources, can render investments which initially appeared cost-justified, and therefore prudent at the time they were made, to be uneconomical at a later date. This potential problem can have deleterious consequences when the investment is very large. This has, in fact, occurred for many new nuclear units throughout the U.S. since 1980. Thus it is important that utility planners incorporate a considerable degree of flexibility in their generation expansion planning process and investment decisions, so that they can react appropriately to changing circumstances in order to maintain the optimum balance between reliability and economics in the face of the options available to them at any point in time.

III. RATE TREATMENT OF INVESTMENTS IN NEW CAPACITY

In recent years, many electric utilities have found themselves with new base-load facilities coming on line at a time when the demand for power that they were expected to serve has not materialized. In addition, these facilities have often turned out to be much more expensive than planned, owing to cost

overruns, and more expensive than other sources of power as a consequence of unanticipated changes in the relative economics of the various generation alternatives.

Commissions regulating these utilities have had to determine whether, or to what extent, their investments in such expensive new capacity should be placed in the ratebase. Unfortunately, regulators grappling with this issue have been hampered by a lack of clear principles to guide them in their determinations as to how they should apply the traditional "used and useful" and "prudence" tests. This is understandable, since the conditions under which electric utility regulators have operated have changed radically over the last decade -- previously the context was one of long-run decline in the real price of electricity, economies of scale in plant construction, and rapid load growth. The substantial diminution of load growth, and the advent of very high cost baseload facilities, especially nuclear plants with costs in the billions, have contributed to situations of excess costs.

Application of the traditional "prudence" and "used and useful" tests prior to the mid 1970s did not create any obvious problems, since large new facilities in that era were typically needed to meet rising demand within a reasonably short period of time, and they benefitted from increasing economies of scale in their construction costs. The situation today is, however, far different, and the regulatory approaches which served well in that earlier period clearly became more problematical in the new and complex environment of the 1980s. This change illustrates a general need for both the practical application of regulatory theory to be refined and adapted to meet changing circumstances, as well as the need for the theory itself to evolve in a manner that allows the goal of distributive justice to be more closely approached under new circumstances.

Most states require that investments in utility plant be both prudent and "used and useful" in order that they may be put into ratebase. In the case of prudence, the determination has not been one of "either/or" but, rather, a matter of degree. That is, Commissions have sought to determine what portion of an investment has been prudently incurred and what portion has been incurred as a result of imprudence (e.g. excessive costs resulting from construction mismanagement). Rate treatment has followed from such determinations, with the imprudent costs entirely excluded from rates. Unfortunately, the second test -- used and useful -- has not been clearly and consistently applied. Indeed, there has been considerable confusion and disagreement as to how this test is to be applied due to the lack of a clear definition. The lack of a systematic approach to this critical regulatory issue has sometimes led to contradictory applications of the "used and useful" test in different states, or even in the same state at different times.

Generally, to be "used" a particular facility must be operational. This is relatively easy to determine. The controversy arises in determining whether new baseload capacity is "useful". Many jurisdictions have approached measuring this aspect of new capacity by measuring its contribution to system reliability - i.e. does the plant contribute usefully to the utility's reserve margin or could it be expected to do so in the foreseeable future, given the need to add new baseload capacity to most systems in fairly large increments. If the new capacity is not thereby useful in serving the needs of system reliability, the capacity would be deemed excess capacity.

ESRG has taken the position that the real question facing regulators in applying the "used and useful" standard in these situations is not whether the new facility contributes to excess capacity, but whether its net economic value is beneficial or detrimental to ratepayers. Defined in this manner the test is, in a sense, applied to the investment in the plant and not the plant itself. The genesis of, and theoretical support for, this distinction between plant and investment has been traced by Roger D. Colton in Excess Capacity: A Case Study in Regulatory Theory and Application, in The University of Tulsa Law Journal, Volume 20. He cites Justice Brandeis' dissenting opinion in the United States Supreme Court decision in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission, "the thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked on the enterprise." (p. 418)

Using this economic approach, the question of whether or not a new base-load plant creates excess capacity becomes irrelevant to the ratemaking disposition of its costs; what is relevant is its net impact on required revenues. This is true for all types of units, though it is especially true for nuclear power plants and the uniquely high costs and economic risks they present. It is important to recognize that this position forces a radical break between the concept of "excess capacity" and the "used and useful" standard, and conflicts directly with many recent Commission decisions that have led to partial ratebase exclusions, for new plant investment, which were based simply upon the "excess capacity" approach. The most controversial implication of this approach is that an investment in a new plant can fail the "used and useful" test if it is deemed to be uneconomical, even if it does not contribute to excess capacity on the system. Conversely, it could pass the "used and useful" test even if it does contribute to excess capacity.

To determine if an investment in new capacity is "useful", then, one must measure its economic value to the system over the long term. This is done by comparing, under current and anticipated conditions, the cumulative costs of the facility in

question to its savings over an appropriate planning period, usually the lifetime of the plant. The costs are those required revenues associated with building and operating the plant, and the savings are the required revenues associated with the lowest cost alternative plan that could have been prudently pursued in its place. For example, such an evaluation could involve comparison of the total revenue requirement impact of a new nuclear plant with that of a coal plant which could have been built instead. Or it could involve comparison of a new nuclear or coal plant with a more optimal plan, if indeed one can be identified, which embodies a mix of conservation, load management, peaking capacity and, ultimately, new baseload capacity when needed. In making this comparison all considerations of adequate reserve margin and system reliability levels are automatically addressed, for these design criteria must be explicitly met by the alternative capacity planning scenario used as the economic baseline. If this economic analysis shows cumulative long-run costs in excess of savings on a present value basis, the new capacity is not the most economic or optimal alternative and is therefore not fully "used and useful".¹

It is important to note that an analysis of the economics of a new facility relative to those of the least cost alternative is based upon current conditions and projections of the future. Thus the degree to which the investment is not fully "useful" may change over time with changes in the relative costs of generation alternatives and with changes in demand. For this reason regulators, in adopting economic value as the measure of "used and useful", should give the utility the option to reapply to have any initially excluded investment placed in rate base should conditions change in the future in a manner favorable to the new investment.)

IV. RATE TREATMENT OF UNECONOMICAL NEW CAPACITY

Once regulators determine the extent to which an investment in new capacity is "used and useful", this amount can be placed into ratebase. However, the regulator must then determine what rate treatment the "uneconomic" portion of the investment is to receive, namely who is to bear these excess costs - ratepayers, stockholders, or each to some degree?

¹ For example, if it is found that a \$2 billion investment will result in cumulative costs far in excess of benefits, while had the investment been only \$1 billion the lifetime benefits would equal the costs (breakeven), it could be said that fifty percent of the investment is "used and useful."

Ratepayers can argue that traditional ratemaking practice requires complete exclusion from rate base of any investment that is not "used and useful". Utility management can argue that if a decision to invest in new facilities was prudent at the time it was taken, then the full value of the resulting investment should be placed in ratebase. ESRG maintains that a reasoned and equitable sharing of these costs usually lies somewhere between these two extremes at a point which can only be determined by the Commission examining the facts of the specific case. This determination can be accomplished through the application of the "prudence" test in combination with the concept of "risk sharing", with imprudence seen as an extreme form of risk-sharing.

Most Commissions are gradually coming to realize that the "prudence" test alone does not provide a realistic way to allocate the costs of uneconomic new capacity between shareholders and ratepayers. Strictly applied this approach maintains that the only costs which should be borne by the utility are those deemed to have been imprudently incurred. Determination of imprudence has had a demanding evidentiary requirement, and rightfully so, for imprudence in this sense implies more than mere error of judgement; the utility's action must be characterized by misfeasance or malfeasance. Yet, this is seldom the explanation for the bulk of the excess costs in the most common situations where new uneconomic capacity has been completed.

Most often new capacity, which at some point seemed cost-justified and prudent, ends up being uneconomical due to a variety of factors. Some of these factors, such as an inadequate planning and review process, could have been much better controlled by utility management; others, such as changing fuel prices or demand growth rates and interest rates, were clearly beyond its control. Moreover, some phenomena beyond the utility's control could reasonably have been anticipated (e.g. certain changes in load growth) or brought under control (e.g. by demand management), while others may have been extremely difficult or impossible to predict (e.g. the oil price increase of 1979). Under these circumstances equity demands that the allocation of the resulting excess costs between shareholders and ratepayers should either reflect the degree of responsibility of each party for the situation at hand, or should reflect a sharing of the risk that no party could control. Adoption of a "risk sharing" approach by regulatory commissions to allocate costs in these situations is based, then, on the notion that the utility management could have pursued a planning process and construction program that was more flexible and therefore one that entailed less economic risk.

As stated above, in applying the risk-sharing concept regulators must be governed by the specific circumstances of the case at hand. The degree to which excess costs should be borne by investors or ratepayers will vary from case to case according to the factors causing the resulting investment to be uneconomic. The types of questions that need to be asked are: What risk reduction strategies were taken or could have been taken by utility management? Did the economics of the project deteriorate suddenly near the end of the project due to external factors (e.g. sudden decline in oil prices) or did they grow gradually worse over the construction period (e.g. due to budget overruns)? Did a public agency approve the utility's construction plan or not, and at what stage in the utility's planning process? Making a decision regarding the appropriate allocation of economic losses between parties based on the degree of utility responsibility is made easier by dealing in terms of economic value, i.e. dollars, which are very amenable to being allocated in the appropriate manner.

The theoretical basis for the use of this "risk-sharing" approach is that all investments involve an element of economic risk, even those investments made by a regulated utility. In a non-regulated business, both rewards and risks are unlimited, and they accrue solely to the investor. In a regulated industry, both the rewards and risks to the investor are limited, but they are not eliminated. This limiting of rewards and risks to the investor is achieved in effect through a sharing of them between investors and ratepayers. Investors, in exchange for accepting the requirement to provide service, are guaranteed a reasonable opportunity to earn a fair rate of return on their investments. Customers, in exchange for the assurance that electricity will be provided, incur an obligation to share some of the economic risks associated with its production. In return for the risk premiums they receive as part of their total return on equity, investors must also bear some of the economic risk associated with their investments.

This argument in support of the need and justification for risk-sharing in the regulatory process has been advanced in some detail by Dr. John Stutz of ESRI in a recent article "Risk Sharing in the Electric Utility Industry", in Public Utilities Fortnightly, April 3, 1986. This perspective is, in large measure, supported by John Colton in "Excess Capacity : Who Gets the Charge from the Power Plant", in the Hastings Law Journal, vol.34, and most recently by a July 10, 1986 editorial in Public Utilities Fortnightly, "The Social Compact and the Sharing of Risk". It is also consistent with the position advanced by the National Regulatory Research Institute in its study entitled Commission Treatment of Overcapacity in the Electric Utility Industry (NRRI-84-10).

V. RECENT REGULATORY DECISIONS ON UNECONOMICAL CAPACITY

In a number of recent regulatory decisions dealing with new base-load units, some Commissions have at least implicitly found that investments in new capacity must be economically justified and that risk-sharing must apply to the portion of those investments which are deemed to be uneconomic. These conclusions are found in orders dealing with new high cost generating facilities completed in the last few years in the following states: Illinois (Louisa), Pennsylvania (Susquehanna 1 and 2), Michigan (Fermi 2), Missouri (Callaway), Kansas and Missouri (Wolf Creek) and Massachusetts (Millstone 3). The basis for two of these decisions, the Kansas and Massachusetts orders, provide clear support for ESRG's approach to determining whether an investment in new capacity is "used and useful" and to the concomitant use of "risk-sharing" in the ratemaking process.

Kansas Corporation Commission - Wolf Creek

In Docket Nos. 142,098-U and 142,099-U, the Kansas Corporation Commission (KCC) examined the requests of Kansas City Gas and Electric (KG&E) and Kansas City Power and Light (KCPL) to include in their rate base their investment in the Wolf Creek nuclear plant. The Kansas Commission implemented the traditional prudence test by determining that a portion of the construction cost was "inefficiently and imprudently incurred". Secondly, over and above this imprudency disallowance, the KCC identified a portion of Wolf Creek as excess capacity, finding that "reserves in excess of 20 percent should be justified from an economic perspective". Finally, the Commission accepted the concept of economic risk-sharing advanced by ESRG in the case.

Based on these findings, the KCC applied the following rate treatment to Wolf Creek. Depreciation and return were disallowed for costs incurred as a result of imprudence. Only a small fraction of the traditional return on investment was allowed for the portion determined to be physical excess capacity. The portion of Wolf Creek that did not represent excess capacity in the physical sense was to be economically "revalued" at the cost of a coal plant, and a full return was allowed on this amount. Here the value of a coal plant seems to have represented what the KCC believed was a reasonable economic baseline against which the cost of generation from Wolf Creek should be measured. At the same time, depreciation of the prudent portion of the nuclear plant investment was permitted in rates. Thus, by this set of measures, a risk-sharing of the excess costs was effected.

In a decision issued on June 13, 1986 the Kansas Supreme Court upheld all the decisions of the KCC against an appeal of its order. The Kansas Supreme Court ruling confirmed the KCC's finding that there is "economic excess capacity" even when overly expensive capacity is needed to meet reliability requirements,

and that the excess costs of such capacity could be shared between ratepayers and investors.

Massachusetts Department of Public Utilities - Millstone 3

The one Commission which appears to have most directly applied ES&RG's approach to measuring economic value as the test of "used and useful", and which appears to have accepted the need for risk-sharing in the regulatory treatment of excess costs, is the Massachusetts Department of Public Utilities. Their decision issued June 30, 1986 in Docket No. 85-270 explicitly applied these principles to the rate treatment of Millstone 3.

With respect to the "used and useful" standard, the Department stated :

The used and useful standard requires the Department to determine whether the utility investment is needed and economically desirable. Need for a new electric utility production plant is established if it can be shown that the investment in question can provide either capacity or energy which is required by the utility, at a net cost which is lower than the cost of the capacity and/or energy which it displaces. Once need for capacity and/or energy savings has been established, the Department must then determine the extent to which an investment is useful and thus the extent to which a return should be allowed on the investment. Even if it could be shown that a utility had an immediate need for additional capacity, such a demonstration in and of itself would not be sufficient to justify a particular generating unit; the Company still must demonstrate that the generating unit it had constructed to meet capacity need was the most cost-effective (Order, pp 64-65)

In its order, the DPU established the economic value of the unit (Millstone 3) by calculating the estimated cumulative net present value of revenue requirements associated with the least-cost alternative generation expansion plan that would have been followed had Millstone 3 not been built. This analysis indicated that the optimum alternative generation scenario had revenue requirements 24 percent lower than the Millstone 3 plan. Based on this analysis only 76 percent of the costs of Millstone 3 were included in the Company's rate base. The remaining 24 percent were to be amortized, without a return, thus resulting in a sharing of the excess costs between ratepayers and investors.

The DPU acknowledged the fact that that its determination of the useful value of the unit was based on the forecast of a number of parameters over the plant's expected operational lifetime. For this reason the Company was allowed to return for further rate relief in the future should one of the key parameter

values used in the DPU's original order turn out to have been significantly in error.

VI. CONCLUSION

Must commissions allow recovery of and return on all utility investments that are prudently incurred, no matter how excessive or uneconomical they may be? In this paper we have answered, "No." We have shown here that commissions can and should apply economic tests to utility costs as a basis for their ratemaking decisions.

The correct ratemaking treatment for an investment in a new power plant must be guided by an analysis of the economic value of that investment. This analysis, based upon the best current information, must compare all costs associated with ratebasing and operating the new facility, with those of an alternative resource plan which is at or near the least cost that could prudently have been achieved. This approach implies that whether a new generating plant is "used and useful" is a matter of degree, the degree to which its overall economics compares favorably to the best alternative that could have prudently been pursued. Thus, it is not simply a matter of "yes" or "no" as to whether a new plant is "used and useful".

The rate treatment of that portion of the investment which is found to be uneconomical, i.e. not "used and useful", is most equitably handled through the application of the prudent investment test in combination with "risk-sharing". Using this flexible approach, regulators can allocate the burden of uneconomical or excess costs between the utility's stockholders and ratepayers in any reasonable proportion, based upon all the factors responsible for the existence of these costs and the circumstances under which they were incurred. Moreover, they can accomplish this allocation in a manner that intrinsically balances the interests of both groups.

DIRECT TESTIMONY

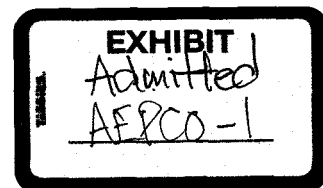
OF

DAVID J. HEDBERG

**ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.**

**IN THE MATTER OF THE COMPETITION
IN THE PROVISION OF ELECTRIC SERVICE
THROUGHOUT THE STATE OF ARIZONA
DOCKET NO. U-0000-94-165**

JANUARY 9, 1998



Summary of David J. Hedberg's Testimony

Cooperatives, especially G&Ts like AEPCO, have been formed by its distribution members to provide power at the lowest long term cost. AEPCO does not have any incentive to charge its members more than is necessary to cover its long term costs but because of its low cost financial structure it has limited ability to absorb losses and this must be taken into consideration in the commissions' decisions.

Recovery of full stranded costs is critical for AEPCO. The stranded cost process should be based on a lost revenue approach with a true up mechanism and be applied to all customers classes including any who may leave the system. This can best be accomplished by a company by company basis.

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**DIRECT TESTIMONY OF DAVID J. HEDBERG
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
IN DOCKET NO. U-0000-94-165**

Q1: PLEASE STATE YOUR NAME AND ADDRESS.

A1: My name is David J. Hedberg, and my business address is Woodland Park, 2201 Cooperative Way, Herndon, Virginia 22071-3025.

Q2: WHAT IS YOUR PRESENT OCCUPATION?

A2: I am employed as the Senior Vice President of Strategic Services at the National Rural Utilities Cooperative Finance Corporation (CFC).

Q3: WHAT ARE YOUR DUTIES WITH CFC?

A3: My duties with CFC involve many areas, but include providing assistance to member cooperatives in the areas of rate of return, rates, acquisitions and mergers. This assistance includes appearing as an expert witness on behalf of the cooperatives in rate case proceedings and providing any other rate or regulatory support as needed. In addition, I am actively involved in CFC's efforts to determine the future changes in the industry, the best way to adapt to these changes and meet the competitive standards of our ultimate consumers. Finally, I am in charge of CFC's workout efforts that involve determining valuations, market prices and what are hopefully creative solutions to maximizing the repayment of debt.

Q4: PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A4: I graduated from Kent State University with a Bachelor of Business Administration Degree in 1972 with a major in Economics and a minor in Finance. In 1976 I received a Master of Arts Degree in Economics. From 1974 to 1976 I worked as an Economic Planner for the government of Botswana in Southern Africa while with the Peace Corps. I was employed by the Federal Energy Regulatory Commission (FERC) from February 1977 until December 1981 when I joined CFC. My responsibilities with FERC included the review and preparation of cost of service and rate design studies of electric utilities involved in rate proceedings before FERC. I have also attended many conferences and courses concerning income taxes, rate design, rate of return, marketing power and energy, and cost of service. These included the National Association of Regulatory Utility Commissioners Annual Regulatory Studies Program at the Graduate School of Business Administration, Michigan State University, East Lansing, Michigan. In addition, I have prepared several papers on a variety of financial subjects concerning the electric utility industry.

Q5: HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE REGULATORY BODIES?

A5: Yes, I have submitted testimony before FERC in the following proceedings:

Commonwealth Edison Company, Docket No. E-9002; Indiana & Michigan Electric Co. Docket Nos. ER78-379, ER78-103, ER76-176; Ohio Edison Co. Docket Nos. ER77-530, ER78-490; Central Illinois Public Service Co., Docket Nos. ER78-80, ER77-89; Ohio Power Co., Docket No. ER80-673; Utah Power and Light Co., Docket No. ER79-121; Kansas City Power and Light Co. Docket Nos. ER80-315, ER80-450; Public Service Co. of New Mexico, Docket Nos. ER80-313, ER81-187; Wisconsin Electric Power Company, Docket No. ER80-567.

In addition, I either supervised or participated in approximately 50 rate cases before FERC that resulted in a settlement of issues so that a hearing was not required.

Q6: HAVE YOU TESTIFIED BEFORE STATE COMMISSIONS PRIOR TO THIS CASE?

A6: Yes, since being employed by CFC, I have testified in about 100 rate cases before approximately 25 state commissions including several before this commission.

Q7: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A7: The purpose of my testimony is to provide a national perspective as to rural electric cooperatives, their regulation and how they differ from investor owned utilities in several important respects. I will also discuss several issues outlined in the 12/2/97 procedural order in this docket including how to determine stranded costs, true up mechanisms, timeframes, price caps/rate freezes, who should pay and stranded cost mitigation factors.

Q8: WHAT ARE THE SECTIONS OF YOUR TESTIMONY?

A8: I will briefly explain CFC and how it operates some of the unique financial and operating characteristics of electric cooperatives and the issues mentioned above specific to this proceeding.

Q9: PLEASE EXPLAIN THE PURPOSE OF CFC.

A9: CFC is a self-help, independent financing institution, organized as a cooperative and operated on a non-profit basis. As a cooperative organization, CFC is member-owned and controlled. The purpose of the organization, as stated in its Articles of Incorporation, is "to provide, secure, and arrange financing for its members and patrons... for the primary and mutual benefit of the patrons of the Associations and their patrons, as ultimate consumers." CFC's equity was originally provided by the member rural electric systems through the purchase of Capital Term Certificates (CTCs). Equity is also provided when borrowers purchase additional CTCs, if required with long-term loans, and through CFC's margins, 70% of which are currently returned to our member-systems as capital credit payments in the year they are allocated, and the other 30% retained for 15 years before being returned to our member-systems.

Q10: HOW DOES CFC FUNCTION IN RELATION TO ITS MEMBERS AND THE CAPITAL MARKET?

A10: CFC functions both as a borrower and a lender. As a lender, CFC makes short and long-term loans to its member-systems. As security for its long-term loans, CFC normally receives a first mortgage on a borrower's facilities. These mortgages and related mortgage notes are used as security to support CFC's collateral trust bonds issued in the public capital market. Through the sale of such bonds, and through the sale of commercial paper and various types of notes, CFC obtains capital to meet the financing requirements of its members. In this role, CFC acts as a borrower from investors.

Q11: WHAT TYPES OF LOANS DOES CFC MAKE?

A11: For both G&T and distribution systems, CFC offers long term secured loans and guarantees that have a wide variety of maturity and repricing options. In addition, CFC provides a variety of short term loans including lines of credit.

Q12: WHY DO THE VAST MAJORITY OF COOPERATIVES DEPEND UPON CFC FOR SUPPLEMENTAL FINANCING, INSTEAD OF EACH INDIVIDUAL COOPERATIVE HANDLING ITS OWN NEEDS?

A12: There are a number of sound reasons for cooperatives to obtain their capital through CFC. By pooling resources and approaching the private capital markets collectively, the systems develop economies of scale and bring a diversified loan portfolio for CFC to offer investors. In addition, CFC brings to the market about

\$1.5 billion in equity, a loan loss reserve and other financial advantages that benefit its members. These financial strengths have earned CFC an AA bond rating.

Q13: WOULD YOU EXPLAIN THE RELATIONSHIP BETWEEN RURAL UTILITIES SERVICES (FORMERLY REA) AND CFC AS IT RELATES TO THE FINANCING OF ELECTRIC COOPERATIVES?

A13: Rural Utilities Services (RUS) is the federal agency that has been responsible for financing the rural electric program for more than 50 years. CFC is the private organization responsible for meeting the capital gap that has developed between demand for funds and funds available from RUS. As RUS' role has declined in the last few years, CFC's role has increased. Under current legislation, cooperatives have had the right to buy out their government debt, and to date, approximately 150 have either done so or started the process.

Q14: WHAT IS THE SIZE OF THE ELECTRIC COOPERATIVE PROGRAM?

A14: Size can obviously be described in many ways. In numbers there are approximately 1,000 electric cooperatives operating in 46 states and servicing about 70% of the land area of the continental U.S. Total assets of this group is in excess of \$60 billion and they serve about 15 million customers representing over 30 million people.

Q15: HOW DO GENERATION AND TRANSMISSION (G&T) ELECTRIC COOPERATIVES DIFFER FINANCIALLY FROM INVESTOR OWNED UTILITIES (IOUS) THAT WOULD BE OF RELEVANCE TO STRANDED INVESTMENT DECISIONS?

A15: G&Ts like AEPCO have traditionally been funded almost entirely with debt as opposed to IOUs who have traditionally used a combination of debt and equity of roughly equal proportions. These differences usually mean the G&T can operate with a lower rate of return but have very little ability to absorb losses such as disallowed stranded costs. Any significant losses may mean the debt is in jeopardy and so a G&Ts ability to raise capital in the future could be severely restricted. This is particularly true in AEPCO's case. As of 12/31/96, it had more than \$35 million in total membership capital deficiency or negative equity. While AEPCO has made significant progress over the past 10 years in improving its negative equity situation, it obviously can ill afford any reversal in that positive trend.

Another important difference between G&Ts and IOUs is the type of customers they serve. AEPCO was formed to serve its six distribution members who control the G&T through the board of directors, who in turn serve their retail customers (members). As Mr. Minson discussed in his testimony, they are bound together by an "all requirements" contract that terminates in 2020. IOUs on the other hand directly serve most of their customers at the retail level with no contracts although

many IOUs do serve some customers at wholesale and some large customers under contract.

Q16: WHY ARE THESE DIFFERENCES BETWEEN G&TS AND IOUS IMPORTANT WITH REGARD TO STRANDED INVESTMENT ISSUES?

A16: These differences are very important because AEPCO's ability to mitigate costs, tolerate rate freezes, absorb unrecovered or delayed recovery of stranded costs is very limited and may be very different from other utilities in the state. If this is not properly recognized in commission stranded cost decisions, it could have a very adverse impact on AEPCO, its distribution members and their retail customers.

Q17: HAVE YOU READ THE REPORT SUBMITTED BY THE STRANDED COST WORKING GROUP CONCERNING STRANDED COSTS?

A17: Yes I have.

Q18: DO YOU AGREE WITH THE DEFINITION OF "STRANDED COST" OR DO YOU HAVE A PREFERABLE DEFINITION?

A18: I understand the intent of the definition but determining the difference between the value of all prudent jurisdictional assets and the market value directly attributable to the introduction of competition will be a very cumbersome undertaking and subject to many interpretations.

I believe a much better approach and what I have used successfully is the "revenue lost" approach. As I have used this approach, it is quite simple. As market prices are determined, a competitive revenue requirements for a utility will be determined by the competitive market place and this will replace the traditional cost based revenue requirements. The difference or the lost revenue (its possible to have gained revenue) can be used to determine the plant and related costs that cannot be supported by the competitive revenue requirement and are thus stranded.

Q19: WON'T THE MARKET PRICES CHANGE OVER TIME AND RESULT IN OVER OR UNDER COLLECTIONS OF STRANDED COSTS AND IF SO HOW CAN THIS BE ADDRESSED?

A19: Yes, over time prices will adjust but will move to the cost of incremental capacity. As prices move, an adjustment mechanism such as fuel adjustment clauses can be used to true up stranded investment recoveries on an annual or bi-annual basis. Trying to predict market prices especially in the early years of competition will be very difficult so an adjustment mechanism is essential to ensure fair treatment of all the parties.

Q20: WHAT IS A REASONABLE TIME FRAME FOR RECOVERY OF STRANDED COSTS?

A20: Time frames adopted to date seem to be varying widely from 5 to more than 10 years. There is no magic in the right time frame and I believe the magnitude of the

stranded investment must first be determined. Then the time frame can be more objectively evaluated when the rate impact from different recovery periods can be determined. In some cases, it may require rate increases if a short period is chosen and for this reason longer time periods may be necessary.

Q21: DON'T MANY STATES CONTEMPLATE RATE REDUCTIONS, PRICE CAPS OR RATE FREEZES?

A21: Yes, several states including California and Pennsylvania expect rate reductions but this is in part due to expected securitization savings that will occur because of the refinancing of stranded costs by securitization bonds. A cooperative like AEPCO, which already uses relatively low cost debt, would be unlikely to experience any significant savings from refinancing and would likely have to pay prepayment penalties to RUS if this was done. Obviously the proceeds from any securitization would have to be used to pay down debt which would correspond to the assets that would be written off or reduced.

As pointed out earlier, a cooperative like AEPCO has very limited cost mitigation potential beyond the steps it is already taking so required rate reductions or rate freezes may actually harm its member retail customers if not done in a prudent manner.

Q22: WHO SHOULD PAY FOR STRANDED COSTS?

A22: Because the state of Arizona has decided to move toward competition at the generation level, there is a presumption that benefits will result. If there are significant benefits to competition, they should clearly be netted by the costs to achieve those benefits. It is hard to imagine that the public interest is served if classes of customers that leave the utility and thus may benefit from competition should not pay their fair share of a system that was built for their benefit. As a result of this, I believe all classes should pay for stranded costs.

Q23: COULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A23: Cooperatives, especially G&Ts like AEPCO, have been formed by its distribution members to provide power at the lowest long term cost. AEPCO does not have any incentive to charge its members more than is necessary to cover its long term costs but because of its low cost financial structure it has limited ability to absorb losses and this must be taken into consideration in the commissions' decisions.

Recovery of full stranded costs is critical for AEPCO. The stranded cost process should be based on a lost revenue approach with a true up mechanism and be applied to all customers classes including any who may leave the system. This can best be accomplished by a company by company basis.

Q24: DOES THIS CONCLUDE YOUR TESTIMONY?

A24: Yes it does.

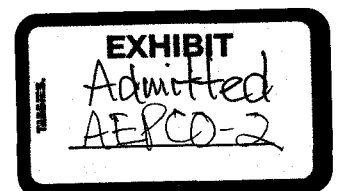
BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
Commissioner - Chairman
RENZ D. JENNINGS
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE COMPETITION) Docket No. RE-00000F-94-0165
IN THE PROVISION OF ELECTRIC)
SERVICES THROUGHOUT THE STATE)
OF ARIZONA)

Rebuttal Testimony
of
William K. Edwards
On Behalf Of
Arizona Electric Power Cooperative, Inc.

February 4, 1998



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TESTIMONY
OF
WILLIAM K. EDWARDS**

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**SUMMARY OF THE
TESTIMONY
OF
WILLIAM K. EDWARDS**

Mr. Edwards testifies that given the non-profit cooperative status of AEPCO, whereby AEPCO is owned by the customers it serves, this makes irrelevant issues of sharing stranded costs between stockholders and customers since AEPCO is owned by its customers.

Mr. Edwards responds to Dr. Rose, the staff witness, on several points. The Commission should not re-evaluate assets already in rate base for the appropriateness for inclusion in the stranded costs recovery process. In AEPCO's case, the obligation to serve is matched by the obligation to buy as enumerated in AEPCO's all requirements agreement with each of its customer owners. Mr. Edwards affirms the need to collect stranded costs. Mr. Edwards also testifies that AEPCO's existing capitalization precludes the equity holder (customer owner) from absorbing stranded costs. Mr. Edwards testifies as to what may happen if the AEPCO cannot recover its stranded costs.

Mr. Edwards affirms the lost revenues approach as the best method for determining stranded costs and suggests that a periodic true-up mechanism would be advisable.

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Rebuttal Testimony of
William K. Edwards
Before the
Arizona Corporation Commission
Docket No. U-0000-94-165

Q. Please state your name, and business address?

A. My name is William K. Edwards, my business address is 2201
Cooperative Way, Herndon, Virginia 20171.

Q. With whom are you employed and what are your responsibilities?

A. I am employed by with the National Rural Utilities Cooperative
Finance Corporation(CFC) as an economist and senior consultant.
In that capacity I assist cooperatives on regulatory issues before
the FERC and many state commissions.

Q. What is your educational background and experience?

A. I received my BS degree in Business with a concentration in
economics from Christopher Newport College of the College of
William & Mary in 1977, and a MA degree in economics from Old
Dominion University in 1979. My major field of study included,
mathematical economics, econometrics, and microeconomics. I have
completed a number of courses toward a Ph.D. in economics from
Virginia Polytechnic Institute & State University. I have worked
for the firm of Ernst & Ernst as a consultant principally in the
electric utility industry. From 1982 to 1985, I was employed by
Mississippi Power & Light Company (Entergy - Mississippi) as an

1 economist responsible for rate research. From January 1986 until
2 early 1995 I was employed by Central Louisiana Electric Company,
3 Inc. as Manager of Rate Research and subsequently as Director of
4 Rates. In that capacity I was responsible for regulatory affairs,
5 regulatory accounting, rate design, cost of services studies, rate
6 administration, and the attendant litigation associated regulatory
7 issues before both the Louisiana Public Service Commission, and the
8 Federal Energy Regulatory Commission. A more comprehensive history
9 of my experience is contained as Exhibit ____ (WKE-1) Schedule 1.

10
11
12 Q. Mr. Hedberg of CFC had filed direct testimony on AEPCO's behalf in
13 this docket. What is his status?

14
15 A. Unfortunately, Mr. Hedberg is presently suffering from pneumonia
16 and is unable to participate in this proceeding. I will adopt Mr.
17 Hedberg's direct testimony as my own.
18
19

20 Q. What is the purpose of your testimony?

21
22 A. The purpose of my testimony is to respond to certain issues raised
23 by various parties in this proceeding. The volume of testimony
24 and divergence of opinion is large, so I will not attempt to
25 respond to all points raised.
26

27 Q. Is much of this testimony relevant, in your opinion, to AEPCO?

28
29 A. No. Many of the parties (large industrial customers, the Attorney
30 General's Office and RUCO, among others) focus on various sharing
31 ratios between stockholders and customers. Without commenting
32 generally on the appropriateness or fairness of these suggestions,
33 they simply have no application to AEPCO. AEPCO is a non-profit
34 electric generation and transmission cooperative. AEPCO's equity
35 is owned by the distribution cooperatives it serves. Therefore,
36 the divergence of interests between equity holders and customers is

1 simply not present in AEPCO's case. AEPCO's customers and equity
2 holders are the same.

3
4
5 Q. Is the obligation to serve a justification for the collection of
6 stranded costs resulting from bad investment decisions?

7
8 A. No. Dr. Rose is correct when he suggests that the obligation to
9 serve is not sufficient to support stranded costs of assets that
10 the Commission would not consider to be prudent or used and useful.
11 However, assets already allowed in rate base should not be reviewed
12 again for their prudence as a part of a stranded costs
13 determination. Such a redundant review increases costs, needlessly
14 complicates proceedings, and subjects the owners, creditors, and
15 equity holders of those assets (which in AEPCO's case is its
16 customers) to unnecessary risks.

17
18 I also do not agree with Dr. Rose's statement that there has never
19 been an obligation to buy on the part of customers of the utility.
20 In fact there was both an obligation to provide service on the
21 part of the utility, as well as an obligation to buy on the part
22 of the customer that was implicit in the monopoly franchise of the
23 utility as granted by the state. Customers were not given a
24 choice of generation suppliers, but their present and future needs
25 had to be anticipated and met by the utility. AEPCO has an all
26 requirements contract with each of its member distribution
27 cooperatives that formalizes this obligation to buy and in turn
28 supports the obligation to supply electricity which its
29 distribution cooperative owners have to their customer owners.

30
31 Q. Should stranded costs be recognized by this Commission?

32
33 A. Yes. This Commission should provide an opportunity for generation
34 owners to collect all of their prudently incurred stranded costs.
35 Failure to provide an opportunity to collect stranded costs will
36 adversely affect generation owners. In AEPCO's case, the impact

1 could be particularly adverse because of AEPCO equity situation.
2 An inability to collect stranded costs may lead to higher rates
3 and therefore would not be in the public interest.
4
5

6 Q. What is the relationship of the National Rural Utilities
7 Cooperative Financing Corporation ("CFC") to AEPCO and the other
8 Arizona cooperatives as well as cooperatives across the country?
9

10 A. CFC is a non-governmental financing organization which provides
11 capital for the electric cooperative utilities across the county.
12 CFC is cooperatively owned by the members it serves. CFC is a
13 creditor for AEPCO as well as a creditor to most of the Arizona
14 cooperatives.
15

16 CFC sells bonds, as well as other securities, of various terms and
17 lends the proceeds to cooperatives seeking capital. The ability
18 to collect the outstanding principal is contingent upon the
19 revenue stream created by the rates charged to their
20 owner/customers. CFC accepts certain risks associated with loans
21 which are not unlike the risks cooperatives accept in providing
22 service to their customers. These risks include, among other
23 things, the risk of interest rate swings, defaults, and by virtue
24 of our close association with our electric utility member owners,
25 the risks associated with utility operations and regulation.
26 Risks are inherent in the electric utility business as well as
27 CFC's core business. Although we seek to mitigate these risks as
28 a normal course of business, cooperatives as well as CFC face
29 these risks on a daily basis. Today, these risks include the
30 risks associated with making the transition from one regulatory
31 method to another. However, should electric cooperatives be
32 forced to make that transition more rapidly than can be reasonably
33 accommodated, or if present generation owners like AEPCO are
34 denied the ability to collect stranded costs, they may suffer
35 irreparable economic harm by not being able to repay creditors
36 money borrowed under various mortgage indentures. These issues

1 threaten cooperatives, their creditors, and their owner/customers
2 with a transition process which, if it is too short or if it fails
3 to provide a means to pay for the assets used for many years to
4 provide reliable service, may result in serious financial stress
5 that would likely increase the cost of providing customers with
6 power and energy. This may, at a minimum, result in an inability
7 to access capital markets, or may only allow access to capital
8 markets at above market rates.

9
10
11 Q. Dr. Rose suggests in his testimony (page 8 lines 4-28) that in a
12 competitive environment companies sometimes do not receive their
13 full investment in assets over time? Do you concur with his
14 analysis?

15
16 A. What Dr. Rose suggests is sometimes true. However, comparisons
17 between competitive markets and regulated markets are irrelevant in
18 this case. The Commission should focus on the best way to
19 transition to a competitive market without economically injuring
20 generation owners in the process. If the transition is
21 successful, the competitive market will provide the incentive to be
22 efficient. Generation utilities in Arizona have not been in the
23 competitive market historically. In a regulated industry there is
24 an opportunity to earn a return on the money invested in prudently
25 constructed assets or in AEPCO's case an opportunity to collect its
26 costs and meet its mortgage requirements. If the Commission fails
27 to provide an adequate transition to a competitive generation
28 market, equity holders (AEPCO's customer owners) and creditors
29 potentially could be injured. The electric generation industry is
30 an extremely capital intensive industries. Debt capital used to
31 construct these long-lived assets is borrowed from investors
32 pursuant to long-term debt instruments that require companies to
33 maintain certain coverage ratios while the debt is amortized.
34 These requirements exist as a means of protecting creditor's
35 capital. Likewise, mortgage requirements provide specific liens on
36 the assets in the event of default or bankruptcy. Dr. Rose's

1 inference generation companies can transition to a competitive
2 environment with something less than full recovery of stranded
3 costs is both unrealistic and unwise.
4

5 Q. What would happen to AEPCO if creditors were made whole, but equity
6 holders were not?
7

8 A. AEPCO's equity holders have no ability to absorb costs. AEPCO's
9 equity holders are the distribution cooperatives served by AEPCO.
10 Presently AEPCO has negative equity on its balance sheet. Highly
11 leveraged capital structures like AEPCO carry special risks that
12 limit its ability to absorb stranded costs. This is why
13 suggestions that stranded costs be shared between customers and
14 equity holders is irrelevant in AEPCO's case. AEPCO is a non-
15 profit generation and transmission cooperative that is owned by the
16 customers it serves. AEPCO has no equity to share. Its owner and
17 customers are one in the same. Hence, there is no conflict between
18 the customers and the equity holders. AEPCO seeks to recover only
19 its cost of providing service plus a small margin to meet its
20 coverage ratios.
21
22

23 Q. What may happen to AEPCO if adequate allowances for stranded costs
24 recovery are not allowed by this Commission?
25

26 A. Even if AEPCO's exposure to stranded costs is minor, the result may
27 be that AEPCO would not have access to capital markets at
28 competitive rates. If AEPCO's exposure to these costs is greater,
29 AEPCO may have far more serious financial problems.
30
31

32 Q. Do you concur that AEPCO should be afforded the opportunity to
33 recover stranded costs only to the extent necessary to "maintain
34 financial stability" (Dr. Rose page 16 lines 26-27)?
35

1 A. To a certain extent, yes. Without debating the precise reasons as
2 to how Dr. Rose arrived at this conclusion, in the case of a non-
3 profit customer-owned cooperative like AEPCO, adequate "transition"
4 revenues to cover costs and meet mortgage requirements are all it
5 seeks or needs.

6
7
8 Q. Do you agree with Dr. Rose's conclusion that the "top down" or
9 "lost revenues" approach to stranded costs should be employed in
10 Arizona?

11
12 A. Yes. The lost revenues approach should be used.

13
14 I do not believe that forced divestiture is a viable means to
15 determine an assets value for the purpose of stranded cost
16 determination in this case. There are serious flaws to that
17 logic. Among them are the fact that forcing a generation owner to
18 sell its assets may be confiscatory. Generation assets are still
19 needed to meet AEPCO's continuing obligation to serve
20 responsibilities. Also, in the case of AEPCO, mortgage indentures
21 and loan covenants may adversely affect the market value and would
22 produce unacceptable costs and delays to unwind the debt.

23
24 The "bottom down" approach described by Dr. Rose and suggested by
25 several other parties would require an appraisal (assuming the
26 assets are not sold to affix the value). Such appraisals are
27 subjective by definition and may not reflect the economic value of
28 the assets.

29
30
31 Q. What methodology should be applied to collect stranded costs?

32
33 A. The lost revenues method should be the methodology used to
34 determine stranded costs. The lost revenues approach is
35 particularly well suited for AEPCO since it seeks only to cover
36 its costs and its mortgage coverage requirements.

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Q. Should the Commission adopt a true-up for the lost revenues approach?

A. I would recommend that the stranded cost mechanism include a true-up procedure. Absent a true-up procedure, the revenues lost approach necessarily requires forecasts of market prices, sales and anticipated revenues for the future. It may also require assumptions regarding the discount rate used to calculate the present value of the stranded costs. Such forecasts are prone to error that is avoidable by use of a true-up mechanism. As a non-profit cooperative, AEPCO seek only to recover those stranded costs necessary to meet its cost of service and mortgage coverage requirements. The lost revenues approach in conjunction with a periodic true-up mechanism meets these goals.

Q. Does this conclude your rebuttal testimony?

A. Yes.

WILLIAM K. EDWARDS

Mr. Edwards is a Senior Consultant at the National Rural Utilities Cooperative Finance Corporation. Mr. Edwards' primary focus is the public utility industry. His areas of expertise include regulation, load forecasting, planning, cost and rate design, and mergers and acquisitions. Mr. Edwards has previously worked for the firm of Ernst & Whinney as a consultant, Mississippi Power & Light Company an operating company of Entergy as a supervisor in the Rate Department, Central Louisiana Electric Company as Director of Rates & Regulation, and Air Liquide America Corporation as an Energy Manager.

PROFESSIONAL EXPERIENCE

Mr. Edwards has extensive experience in the above listed areas. Representative projects are listed below for each of these areas.

Regulation. Mr. Edwards has broad and extensive experience in regulatory matters both as a consultant and as a utility executive. As Director of Rates for Central Louisiana Electric Company, Mr. Edwards had the responsibility for planning and successful execution of a number of dockets before both the Louisiana Commission and the FERC. Such experience includes, but is not limited to the following projects.

- Indiana Power & Light Rate Design Efforts Before the Indiana Commission
- ISES 1 & 2 rate proceedings before the Mississippi Public Service Commission
- Grand Gulf Rate proceeding before the Mississippi Public Service Commission
- Dolet Hills rate proceeding before the Louisiana Public Service Commission
- Wholesale rate proceeding before the FERC on behalf of Mississippi Power & Light Company
- Wholesale rate proceeding before the FERC on behalf of Central Louisiana Electric Company
- Transmission rate proceeding before the FERC on behalf of Central Louisiana Electric Company
- Antitrust case before the FERC on behalf of Central Louisiana Electric Company.

Load Forecasting. Mr. Edwards has been involved in many load forecasting efforts with the utility industry and has participated in the industry debates regarding the evolution of methodologies for forecasting. Some of the companies Mr. Edwards has been involved with include the following.

- Wisconsin Public Service Commission - A review of the forecasting methodologies of the Wisconsin Utilities
- Delmarva Power & Light - Advance Plan Proceedings before the Delaware Commission
- Entergy - Forecasting Committee
- Central Louisiana Electric Company - Development of an econometric load forecast 1985-1995
- Aluminum Association of America - electric end-use and econometric approaches to load forecasting.

Planning. Mr. Edwards has extensive knowledge and experience with production costing models (e.g. PROMOD and POWRSYM) and load flow models (PTI and Westinghouse).

- Entergy - determination of fuel savings attributable to load and unit changes
- Central Louisiana Electric Company:
 - Fuel Budgets,
 - Analysis of Savings from Joint Dispatching,
 - Generation Planning
 - Rate Studies, and
 - Loss Studies.

Cost & Rate Design. Mr. Edwards has had extensive experience with cost analysis/determination and rate design for a number of companies including:

- Northern Indiana Public Service Company
- Delmarva Power & Light
- Arkansas Power & Light
- Mississippi Power & Light
- Louisiana Power & Light
- New Orleans Public Service Company
- Missouri Public Service Company
- Iowa Public Service Company
- Wisconsin Public Service Company
- Empire District Power Company
- New York State Gas & Electric Company
- Iowa Power & Light Company
- Allegheny Power System
- Central Louisiana Electric Company
- Air Liquide America Corporation

Mergers & Acquisitions. Mr. Edwards has performed a number of merger & acquisitions studies for various clients including several of the more recent projects are presently in progress and cannot be disclosed herein:

- Central Louisiana Electric Company
- MidWest Energy

TESTIMONY

Mr. Edwards has testified before the following Commissions on a broad range of topics:

<u>Company</u>	<u>Jurisdiction</u>	<u>Subject</u>
NIPSCO	Indiana	Long-Run Marginal Cost
IP&L	Indiana	Long-Run Marginal Cost
MP&L	Mississippi	Econometric Forecasts
MP&L	FERC	Financial Model/Rate of Return
CLECO	Louisiana	Rate Design/Revenue Recovery
CLECO	Louisiana	FASB 106 Issues
CLECO	Louisiana	Securities Issuances
CLECO	Louisiana	Securities Issuances
CLECO	Louisiana	Securities Issuances
CLECO	FERC	Cost of Service/Rate of Return
CLECO	FERC	Cost of Service/Rate of Return
CLECO	FERC	Cost of Service
CLECO	FERC	Antitrust Issues
CLECO	FERC	Antitrust Issues
Air Liquide	Washington	Restructuring
Air Liquide	Texas	Restructuring
Air Liquide	Arizona	Rates/Corporate Structure
Air Liquide	Louisiana	Short-Run Marginal Costs and Non-Firm Rates
Idaho Co-ops	Idaho	Restructuring
Central Elect Co-op	Montana	Antitrust

EDUCATION

Mr. Edwards holds a B.S. degree in Economics from Christopher Newport College of the College of William & Mary (with distinction) and a M.A. degree from Old Dominion University in Economics. Mr. Edwards' fields of concentration include econometrics, mathematical economics, and microeconomics. Mr. Edwards has completed the majority of requirements for the Ph.D. degree in economics at Virginia Polytechnic Institute & State University.

PUBLICATIONS AND PRESENTATIONS

Mr. Edwards has published or has spoken at the following industry conferences:

- "Role of Antitrust Laws in the Restructuring Process", Kentucky Association of Electric Cooperatives, September 1997.
- "FERC Regulation of Cooperatives", National Rural Utilities Cooperative Finance Corporation Seminars in Denver, Washington, and Atlanta February/March 1997.
- "The Essentials of FERC Regulation of Cooperatives", In conjunction with N. Beth Emery, Esq. And Daniel E. Frank, Esq. On behalf of the National Rural Utilities Cooperative Finance Corporation, February 1997.
- "Unresolved FERC Rate Making Issues", National Rural Utilities Cooperative Finance Corporation Independent Borrowers Conference, July 2, 1997.
- "Major Issues Facing the Electric Utility Industry As A Result of Restructuring", Texas Cooperative Accounting Association, June 1997.
- "FERC's New Merger Policy", National Rural Utilities Cooperative Finance Corporation, March 1997.

- "Acquisitions and the Future of Electric Distribution Cooperatives", Presentation Before the Indiana Statewide Association of Electric Cooperatives, August, 1996.
- "The Economics of Acquisitions, Presentation Before the National Rural Electric Cooperative Association, June 1996.
- "Comments Regarding Electric Industry Restructuring", on behalf of Air Liquide America Corporation for the FERC 1995.
- "Non-Firm Industrial Rates: Economic Justification Vs Marketing Justification", Presentation Before the Southeastern Electric Exchange, April 1992.
- "Econometric Elasticity Measures Using Directly Estimated Differential Equations", Presentation Before the Southeastern Electric Exchange, October 1989.
- "Role of Marginal Costs in the Rate Making Process", Entergy Rate Conference, June 1984.
- "An Inverse Limit Theorem to the Core of the Economy", Old Dominion University Thesis for the Degree of Master of Arts in Economics, Summer 1979.

PROFESSIONAL AFFILIATIONS

Mr. Edwards is a member of the American Economic Association (AEA), the American Law and Economics Society, and the American Statistical Association. In 1993, Mr. Edwards served as chairman of the Southeastern Electric Exchange's Rate Section. Mr. Edwards has additionally been a member of the Edison Electric Institute's Rate Committee.

BEFORE THE ARIZONA CORPORATION COMMISSION

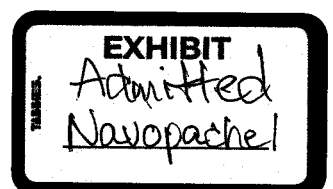
JIM IRVIN
COMMISSIONER-CHAIRMAN
RENTZ D. JENNINGS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

IN THE MATTER OF THE COMPETITION IN)
THE PROVISION OF ELECTRIC SERVICES)
THROUGHOUT THE STATE OF ARIZONA.)
_____)

DOCKET NO. U-0000-94-165

TESTIMONY OF ALAN PROPPER
ON BEHALF OF
NAVOPACHE ELECTRIC COOPERATIVE, INC.

JANUARY 9, 1998



**Summary of the
Testimony of Alan Propper
on behalf of
Navopache Electric Cooperative, Inc.**

Docket No. U-0000-94-165

Navopache Electric Cooperative, Inc. is a distribution cooperative and its stranded costs come primarily from its all-requirements contract to purchase power from Plains Electric Generation and Transmission Cooperative, Inc. Navopache is actively seeking to restructure this all-requirements contract and thereby lower its potentially stranded costs.

I recommend that the Commission not foreclose creative solutions to stranded cost issues that could be worked out by distribution cooperatives and their generation and transmission suppliers.

I recommend that the Commission encourage all distribution cooperatives and G&Ts to reduce the risk of additional stranded investment exposure by avoiding obstacles to restructuring all-requirements contracts that they may work out. In particular, Arizona distribution cooperatives are working with G&Ts to convert all-requirements contracts to partial requirements contracts. The Commission should encourage this creation of opportunities to lower costs and enable member-customers of distribution cooperatives to have meaningful choices among electric suppliers.

I recommend that the Commission leave the current Rules as they are and retain the flexibility to deal effectively and fairly with all the utility-specific features that will be presented in stranded cost recovery hearings.

I recommend that the Commission give greater weight to calculations of stranded cost based on the sale price of generation resources than to calculations based on administrative methods.

I recommend that the market price of electricity used in administrative valuations of power supply stranded costs reflect the mix of spot market purchases and short, medium, and long term contracts.

I recommend that a true-up mechanism be used unless all potentially stranded resources are sold or unless there are no stranded costs.

**Testimony of Alan Propper
on behalf of
Navopache Electric Cooperative, Inc.**

Docket No. U-0000-94-165

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1 Q. Please state your name, position, and business address.

2
3 A. My name is Alan Propper. I am the Regional Manager and Principal Executive
4 Consultant for Resource Management International, Inc. in Phoenix Arizona. My
5 business address is 302 N. 1st Avenue, Suite 810, Phoenix, Arizona 85003.

6
7
8 Q. Whom are you representing in these proceedings?

9
10 A. I am specifically representing Navopache Electric Cooperative, Inc. (Navopache).
11 However, my testimony expresses my beliefs, concerning stranded costs, for all
12 distribution cooperatives, which include members of the Arizona Electric Power
13 Cooperative, Inc. (AEPCO Members). Both Navopache and the AEPCO Members
14 are electric distribution cooperatives in Arizona named as Affected Utilities in
15 Arizona Corporation Commission (Commission) Decision No. 59943 concerning
16 "Competition in the Provision of Electric Service".

17
18
19 Q. What are your qualifications to testify as an expert witness?

20
21 A. My qualifications appear in Attachment 1.

22
23
24 Q. What is the purpose of your testimony?

25
26 A. The purpose of my testimony is to respond to the nine questions put forth as issues
27 in the December 1, 1997 Procedural Order in this Docket and the First Amended
28 Procedural Order dated December 11, 1997, discuss the nature of the electric
29 distribution cooperative with regard to competition and stranded costs, and present
30 Navopache's position on competition and stranded cost recovery in the provision of
31 electric services by distribution cooperatives.

32
33
34 Q. Do you have any general recommendations for the Commission?

35
36 A. I have several. Specific methodological recommendations are presented in detail
37 later in my testimony. My general recommendations for the Commission are:

- 38
39 ➤ Do not foreclose creative solutions to stranded cost issues that could be worked
40 out by distribution cooperatives and their generation and transmission
41 suppliers, as well as their lenders.
42 ➤ Encourage the distribution cooperatives, like Navopache and the AEPCO
43 Members, and the generation and transmission cooperatives (G&Ts), like Plains
44 Electric Generation and Transmission Cooperative, Inc. (Plains) and AEPCO, to
45 reduce the risk of additional stranded investment exposure by avoiding
46 obstacles to restructuring all-requirements contracts that distribution
47 cooperatives and G&Ts may work out.

- Retain flexibility. There are significant differences among the cooperatively-owned, municipally-owned, and investor-owned utilities, as well as individual utilities within these classifications. Further, knowledge of electric markets will grow over time. Do not lock into today's perceived solutions.
- Use the market. Administrative calculations of stranded costs will not reflect all the factors that potential purchasers of power plants would take into account, and there is a possibility that stranded costs will be over-estimated when administrative calculations are used. Whenever possible, market valuations of generating resources should be used.

Q. Do you have any specific recommendations for the Commission?

A. My specific recommendations are presented below in the context of responses to each of the questions/issues posed in the Procedural Orders.

Q. What are the most important issues to Navopache?

A. All of the issues raised in the Procedural Orders are important to Navopache. The most important are the first three – the need for modification of the rules, the timing of stranded cost filings, and the scope and calculation of stranded costs. The scope and calculation of stranded costs is the single most important issue.

1. Modification of Rules

Q. Should the Electric Competition Rules be modified regarding stranded costs, and if so, how should they be modified?

A. I believe that the Rules are sufficient as written. The Rules provide the Commission with the flexibility needed to accommodate the particular characteristics of each Affected Utility and its customers. Any specific guidance or directives issued by the Commission on stranded costs beyond the scope of the Rules should be done by Commission Order. It is highly likely that the Commission will modify any guidance or directives over time to reflect additional data and information, as well as experience in the application of the Rules.

2. Timing of Stranded Cost Filings

Q. When should Affected Utilities be required to make a stranded cost filing pursuant to A.A.C. R14-2-1607?

A. There are two cases. If an Affected Utility does not desire to recover stranded costs or if it has no stranded costs, no filing is necessary. If an Affected Utility desires to recover stranded costs, it should file at least six months before the date when it

1 wishes to begin collecting revenues to recover stranded costs. This will give the
2 Commission time to review the request.
3
4

5 3. Scope and Calculation of Stranded Costs
6

7 Q. What costs should be included as part of stranded costs?
8

9 A. The definition of stranded cost in A.A.C. R-14-2-1601(8) indicates that stranded costs
10 are the verifiable net difference between all the prudent jurisdictional assets and
11 obligations necessary to furnish electricity acquired or entered into prior to
12 December 26, 1996 under traditional regulation and the market value of those assets
13 and obligations directly attributable to the introduction of competition under the
14 competition rules. I believe this definition provides the necessary flexibility for the
15 Commission to consider the particular characteristics of each utility and its
16 customers.
17
18

19 Q. For background, would you briefly discuss the concept and function of an electric
20 distribution cooperative?
21

22 A. Looking back in our history, investor-owned utilities had little interest in extending
23 their lines to serve rural consumers where low population density meant greater
24 distances between service points. In 1935, fewer than 750,000 of the 6.8 million
25 farms in the United States had access to central station electric service. Those that
26 did paid high fees to cover the power company's investment in facilities to serve
27 them and also paid higher power costs than electric consumers in urban areas. In
28 1935, the Rural Electrification Administration (now the Rural Utilities Service, RUS),
29 was established to provide electric service to people in rural areas. The electric
30 cooperative became the means by which this objective was to be achieved.
31

32 Distribution cooperatives were created under federal and state law as non-profit
33 corporations and financed with direct federal loans or federally guaranteed loans.
34 The function of the distribution cooperative has been to electrify their service areas
35 and to bring a sense of community and community service to the areas they serve.
36 Distribution cooperatives are service area specific, member-governed, non-taxable,
37 and dedicated to providing service at cost plus a margin for contingencies, with all
38 other margins and benefits being required by law to be returned to members.
39

40 Distribution cooperatives constructed the distribution facility infrastructures which
41 have made electricity available to consumers in rural Arizona. These distribution
42 systems either self-generated or purchased their electricity from investor-owned or
43 public facilities until the late 1950s and early 1960s. During that period they joined
44 together in Arizona and New Mexico to create the generation and transmission
45 organizations we know as AEPCO and Plains. Distribution cooperatives can
46 survive and continue to provide their special brand of services to their owner-

1 members if the Commission carefully constructs its program of statewide
2 competition.

3
4
5 Q. Are there any unique features of cooperatives that bear on stranded costs?

6
7 A. Yes. Unlike investor-owned utilities, cooperatives do not have investors who could
8 shoulder some of the stranded costs. Distribution cooperatives are required to
9 operate as non-profit entities under special tax law provisions. They have no
10 common or preferred stock or stockholders and they fund operation expenses from
11 margins and from debt.

12
13 Cooperatives have borrowed from the federal government to pay for serving their
14 certificated areas, and they must be able to repay their debts to the United States to
15 the extent possible. Therefore, the ability to recover stranded costs is of the utmost
16 importance to the customer-members of Navopache and, presumably, to the AEPCO
17 Members.

18
19 In addition, as all-requirements and potentially partial-requirements customers of
20 the G&Ts, the interests of the distribution cooperatives, with respect to stranded cost
21 recovery, could differ from the interests of the G&Ts as I will discuss below. Thus,
22 the methodology for the calculation and recovery of stranded costs will have a major
23 effect on the ability of the distribution cooperatives to compete and survive in the
24 unregulated marketplace. Until stranded costs and rates are determined for the
25 power supplying entities, the distribution cooperatives cannot establish their own
26 rate levels and designs, or their terms and conditions for service.

27
28
29 Q. What is the source of most of the potentially stranded costs of the distribution
30 cooperatives?

31
32 A. A distribution cooperative service area is a community with two potential stranded
33 costs. The first is potential stranded costs related to distribution infrastructure for
34 which there is associated debt. This debt must be paid by the service area
35 community. Second, as the agent of this community, the distribution cooperative
36 has an all-requirements contract to purchase electricity equivalent to its load. At
37 present, the all-requirements contract is the major source of potentially stranded
38 costs of distribution cooperatives such as Navopache as well as AEPCO Members.

39
40
41 Q. What is the purpose of all-requirements contracts?

42
43 A. Distribution cooperatives were not required to guarantee the loans made by the
44 United States government to the G&Ts. In lieu of a guarantee by the distribution
45 entities, the United States accepted an agreement whereby the distribution
46 cooperatives would agree to buy all their requirements for electricity from the G&T,
47 which became the actual borrower of funds.

1
2 Currently, both Navopache and the AEPCO Members buy power and energy from
3 generation and transmission cooperatives, Plains and AEPCO, respectively, under
4 such all-requirements contracts. The purpose of these specific agreements was to
5 give the United States government (specifically the RUS) collateralization and
6 security for the loans it made to Plains and AEPCO for construction of power plants
7 and associated transmission facilities. For Plains, it was the Escalante plant (PEGS),
8 and for AEPCO, it was the Apache plant. It should be noted Navopache was
9 accepted into Plains by Plains and RUS after all of the Plains debt for its PEGS
10 power plant was approved with no reliance on Navopache membership as a
11 security element for the loan.
12

13 It was not the philosophy of the all-requirements contract, nor was there any need
14 for the lender, to expect such a restrictive agreement to be effective in perpetuity,
15 since the loan to be secured was tied to specific generation and transmission
16 facilities. This is particularly true for a plant that is operated at capacity, such as
17 PEGS. Yet, these agreements still exist, though they are being rigorously contested
18 before several forums by Navopache and other distribution cooperatives across the
19 United States. RUS and other lenders to cooperatives are now willing to consider
20 different types of collateralization for both old and new loans, and are developing
21 partial-requirements as opposed to all-requirements contracts. The restructuring of
22 the six billion dollar debt of the Oglethorpe Power Cooperative in Georgia is an
23 example of the use of partial-requirement contracts.
24
25

26 Q. Why are such all-requirements contracts creating major competition-related
27 problems today?
28

29 A. Many distribution cooperatives, such as Navopache are unable to buy power and
30 energy, even for incremental sales to new or expanding loads, at market prices, but
31 must continue to pay above-market prices for the uneconomical power supply
32 blends of their G&Ts. This creates an uncompetitive situation and, therefore, a
33 stranded cost. Without Commission intervention or other action, there is little
34 incentive for a G&T to enter into the best power supply deals available and no
35 market discipline for poor performance. The current all-requirements contracts
36 should not be interpreted as a permanent restriction on distribution cooperatives.
37 Indeed, in light of national energy policy, as well as the Commission's desire to
38 obtain the benefits of competition for retail consumers, it is reasonable to expect that
39 the all-requirements contracts may be modified to enable distribution cooperatives
40 to make market priced electricity available to the member-customers at least for
41 power and energy required for loads in excess of a distribution cooperative's
42 computed share of the capacity of the specific G&T resources constructed or
43 purchased in the past. If member-customers of the distribution cooperative are
44 permitted choice among power suppliers, then the distribution cooperative should
45 also be permitted a choice of power suppliers.
46
47

...

1 Q. How are proposals for restructuring the G&Ts related to the competitive issues
2 being examined at this time, and, particularly, in the development and handling of
3 stranded costs?
4

5 A. As members of the G&Ts, Navopache and the AEPCO Members are aggressively
6 pursuing restructuring plans for Plains and AEPCO, respectively, that would allow
7 them to become partial requirements members, to sever their relationships with the
8 G&Ts altogether, or to remain all-requirements members but lower their power
9 supply costs to a marketplace level at least for incremental purchases and sales.
10

11 Navopache has embarked on a two and a half year analysis on behalf of its member-
12 customers to determine how to make available to them market based electricity and
13 services now contemplated by the Commission Rules. Navopache has taken the
14 highly visible position that Plains must find a way to significantly lower its power
15 supply costs, whether through merger with a financially healthier G&T, debt
16 forgiveness by RUS, or even bankruptcy. However, even if such a remedy is found
17 and implemented, Navopache would want its freedom to choose partial
18 requirements service or complete independence from Plains.
19

20 AEPCO is in the process of concluding a restructuring program which resulted in its
21 members accepting a report which, if implemented, will direct AEPCO to divest
22 itself of generation and transmission and to create three new entities, a Genco, a
23 Transco and a services entity, all of which will be separate corporations. The
24 AEPCO Members have committed to creating partial requirement contracts for its
25 Genco and Transco services based on formulas for "capped" financial responsibility,
26 developed by the AEPCO Members and AEPCO staff. This process is anticipated to
27 be completed in late in 1998, and the Commission should urge and facilitate its
28 completion.
29

30 This restructuring of the G&Ts, with resulting lower power supply costs and at least
31 partial marketplace freedom for the distribution cooperatives, is essential for the
32 survival of Navopache and, in my opinion, AEPCO Members in a competitive
33 marketplace. It should also lower the stranded costs attributable to uneconomical
34 power supply agreements.
35
36

37 Q. How could the timing of the introduction of competition into existing service areas
38 affect stranded costs?
39

40 A. The potential for lowering power supply costs in the near future is very real for the
41 distribution cooperatives. If this occurs, the magnitude of stranded costs could be
42 significantly lowered. In addition, the very nature of a distribution cooperative's
43 business and relationship to its member-customers could be altered, or kept from
44 being altered, by such a cost change. This, in turn, could affect the magnitude and
45 nature of the competition a distribution cooperative would experience and,
46 ultimately, the nature of the organization that the cooperative would become. There

1 should be some coordination of the timing of the lowering of power supply costs
2 with the introduction of competition for the distribution cooperatives.
3
4

5 Q. How does the nature of the distribution cooperative relate to the concept of stranded
6 costs?
7

8 A. The methodology for calculating stranded cost should focus on an allocation of the
9 electricity-providing resources fairly attributed to a distribution cooperative at a
10 certain point in time. That would constitute the maximum amount of generation-
11 related cost and investment to be examined. Whether or not it is stranded is another
12 matter. If it is stranded, the member-customers of the distribution cooperative
13 ought to have a period of time to recover the stranded costs. At the same time, it
14 should be freed from all-requirements contracts binding it to an uneconomic power
15 supply source, and allowed to chose supplemental suppliers.
16
17

18 Q. How does the nature of distribution cooperatives have any bearing on the
19 methodology for calculating and recovering stranded costs?
20

21 A. In dealing with the allocation of power supply resources, or stranded costs, of the
22 cooperatives, purchased power contracts are involved as opposed to a direct
23 investment in uneconomical generating facilities. Possibly complicating the issue is
24 the fact the there is an involvement in these facilities by the distribution cooperatives
25 who are the members of the G&Ts. Another complicating factor is that the
26 methodology chosen to define the stranded costs of the G&Ts will undoubtedly
27 affect the stranded costs of the distribution cooperatives.
28

29 In the case of the AEPCO Members, their supplier, AEPCO, is an Affected Utility
30 under the Commission's jurisdiction whose stranded costs will ultimately be
31 defined by the Commission. However, in the case of Navopache, its supplier,
32 Plains, is not an Affected Utility under the jurisdiction of the Commission, and,
33 therefore, we do not know at this time how and when Navopache's stranded costs
34 will be defined.
35
36

37 Q. How should stranded costs be calculated for an electric utility cooperative?
38

39 A. For the case of a distribution cooperative, the calculation is a two stage process. The
40 first stage is independent of the operations of the distribution cooperative. The G&T
41 must define and calculate the stranded costs associated with its power supply
42 facilities. The second stage is for the distribution cooperative to define and
43 calculate the stranded costs associated with its individual wholesale power supply
44 agreement with the G&T, plus any other stranded costs of the distribution
45 cooperative.
46
47

...

1 Q. How should the stranded costs associated with the power supply facilities of a G&T
2 be calculated?

3
4 A. I believe that two general methodologies should be considered. I refer to them as
5 administratively calculated stranded costs and stranded costs based on the market
6 valuation of assets.

7
8
9 Q. Please describe administratively calculated stranded costs.

10
11 A. Administratively calculated stranded costs should reflect a net present value
12 calculation of the net revenues of sales from the utility's generation sources. The net
13 present value calculation should examine the stream of revenues from sales by the
14 utility, in this case the sales of the G&T to the distribution cooperatives. The present
15 value calculation should also examine the stream of avoidable power production
16 costs facing the G&T. These include fuel and variable purchased power costs,
17 variable operating and maintenance costs, and future capacity additions. A more
18 sophisticated analysis would use a model which examined several scenarios and
19 weighted each by the probability of its occurrence.

20
21 If the present value of the stream of revenues minus the present value of the stream
22 of avoidable costs is positive, those net revenues should be compared with the book
23 value of the potentially stranded costs (such as obligations to pay the principal on
24 loans made for the construction of the generating plant). Recovery of the book value
25 through rates would be allowed under traditional regulation. If the present value of
26 the net revenues is less than the book value of fixed obligations, the difference
27 between the two is stranded cost. If the present value of the net revenues is greater
28 than the fixed obligations, there is no stranded cost.

29
30 In the case where the present value of the stream of revenues is less than the present
31 value of the stream of avoidable costs, the net revenues should be zero for the
32 purpose of calculating stranded costs, and the utility should cease operating its
33 generation facilities or buying power.

34
35 These administratively calculated stranded costs should be used when the market
36 value of power production assets is not obtainable.

37
38
39 Q. Please describe market valuation of power production assets.

40
41 A. A buyer contemplating the purchase of power production assets such as a
42 generating plant would consider the present value calculation described above. But,
43 in addition, it would also consider the strategic value of the assets in providing
44 reliable service, in enhancing its marketplace position, and in gaining credibility by
45 having adequate resources to supply power in the region. In other words, some
46 entities, who would be candidates to purchase physical power supply assets, could
47 value those assets differently than would occur in a "standard" electric utility

1 evaluation. As a result, a buyer might pay more than the present value of the net
2 revenues from the resources as calculated using the administrative method
3 described above. Further, different buyers may have different estimates of the
4 present value of net revenues, of market prices, and of strategic values. The buyer
5 with the highest value should be used to set the market price. Consequently, alleged
6 stranded costs determined by market value could be significantly lower than
7 estimated under the administrative calculation and could possibly be zero. Market
8 valuation also provides a more accurate depiction of stranded costs, providing valid
9 data are available.

10
11 Q. Have buyers paid more than the book value of power production resources?

12
13 A. Yes. U.S. Generating purchased 5,000 MW of generation assets from New England
14 Electric System for \$1.59 billion which exceeded book value by over \$500 million.
15 Southern California Edison sold 10 fossil-fueled generating plants for \$1.115 billion;
16 the book value of the plants was \$421 million. Duke Energy Power Services bid \$501
17 million for three Pacific Gas and Electric plants (2,645 MW) which is about \$120
18 million more than book value.¹

19
20
21 Q. How should the market price of electricity be estimated for use as a factor in the
22 determination of stranded costs described above?

23
24 A. The market price is a critical factor in calculating stranded costs when an
25 administrative calculation is used. I believe that generating utilities should use the
26 best estimate of the average price paid for electricity in the competitive market. This
27 estimate should consider not only spot market purchases (such as at the spot market
28 at Palo Verde and other southwestern hubs) but also prices paid for electricity
29 purchased under short, medium, and long term contracts.

30
31 Before competition starts, the average price is unknown. Estimates of average spot
32 prices would be about \$25 per MWH based upon prices paid at Palo Verde. Spot
33 prices at all southwestern hubs should be included. In the long run, prices should
34 tend toward long run marginal cost. At favorable natural gas prices, long run
35 marginal cost could be \$35 per MWH but if natural gas prices rise, long run
36 marginal cost could be \$45 per MWH. Specific selection of long run marginal costs
37 should be made using clearly stated assumptions about technology, capital costs,
38 operating and maintenance costs, fuel costs, heat rates, capacity factors, time
39 horizons, and discount rates. Specific assumptions should withstand scrutiny by the
40 Commission and other parties.

41
42 I recommend that any needed estimates of market prices consider both spot market
43 prices and contract prices and that the Commission take into account pertinent
44 testimony in stranded cost hearings regarding the relative importance of spot
45 market and contract purchases.

46

¹ *Independent Power Report*, August 22, 1997, p. 20; *Global Power Report*, November 28, 1997.

1
2 Q. Should the Commission give greater weight to a generating utility's administrative
3 calculation of stranded costs or to the comparison of book value with the sale price
4 of a resource?

5
6 A. Greater weight should be accorded to the comparison of book value with the sale
7 price, when such information is available. As I suggested above, administrative
8 estimates cannot take into account all the factors that affect the value of a resource to
9 a buyer. The Commission should consider the range of administrative estimates of
10 stranded costs submitted by utilities and other parties in stranded cost hearings. In
11 contrast, the sale price (assuming the sale were an arms-length transaction) is solid
12 evidence of the market value of the resource which can be compared with the
13 regulated book value. The deference given to sales prices should be an incentive for
14 utilities to sell generating resources where possible if a major priority of the utility is
15 to recover all stranded costs.

16
17
18 Q. How should stranded costs associated with power supply be calculated for a
19 distribution cooperative?

20
21 A. In general two approaches can be taken. The first would be to assume that an
22 allocation of the stranded costs of the G&T would be passed through to the
23 distribution cooperative and would become the distribution cooperative's power
24 supply related stranded costs. The second would be to perform a similar calculation
25 to that discussed above for a G&T, except that the costs associated with the
26 distribution cooperative's power supply contract would be substituted for the G&T's
27 generation costs. Though the results of the two approaches may be similar, the
28 concepts are quite different, with the second approach being more theoretically
29 correct since it is the power supply contract with the G&T that is causing the
30 distribution cooperative to have a stranded cost and not the power supply resource
31 itself.

32
33
34 Q. How should the revenue from retail sales be computed?

35
36 A. If a determination of net present value of the net revenues from retail sales is to be
37 made before competition starts, it would be necessary to value these sales at
38 regulated rates. After competition starts, the sales should be valued at market
39 prices. During a phase-in period, sales in the competitive market should be valued
40 at market prices and sales in the regulated portion of the market should be valued at
41 regulated prices. In addition, after competition starts, the Commission, under
42 A.A.C. R14-2-1614, will have better information on kWh sales and revenues in the
43 competitive market from each energy service provider. Those data can be used to
44 calculate average market prices.

1 Q. What are the implications of the Statement of Financial Accounting Standards No.
2 71 (SFAS 71) resulting from the recommended stranded cost calculation and
3 recovery methodology?
4

5 A. I am not able to address this issue from an accounting perspective since I am not an
6 accountant. However, from a common sense perspective, if stranded costs are small
7 or zero, it should not be an issue. If a utility has the opportunity to recover its
8 stranded costs, as determined by the Commission, SFAS 71 would not seem to be an
9 issue.
10
11

12 4. Time Horizon for Calculating Stranded Costs
13

14 Q. Should there be a limitation on the time frame over which stranded costs are
15 calculated?
16

17 A. Yes. As I indicated above, streams of future costs and revenues must be calculated.
18 Therefore, a time horizon must be selected for the calculation. I propose that the
19 following time horizon be selected (which could be different for each utility):
20

21 The shorter of:

- 22
23 a) the average remaining book life of the utility's relevant assets and
24 obligations, and
25 b) 15 years.
26

27 There is great uncertainty about future costs and revenues, so the present value of
28 net revenues should be calculated with a commensurably large discount rate.
29 Discounting future costs and revenues render insignificant events after 15 years and
30 possibly events ten years out.
31
32

33 5. Time Period for Recovery of Stranded Costs
34

35 Q. Should there be a limitation on the recovery time frame for stranded costs?
36

37 A. When the Commission reviews stranded cost recovery proposals, it should consider
38 the impact on the utility and consumers of varying the time period for recovering
39 stranded costs. For example, too short a time period might result in a stranded cost
40 recovery charge that is so high that it imperils competition. Conditions will vary
41 from case to case.
42

43 Analyses of stranded costs conducted for other utilities suggest that there is no one
44 best time frame, considering the magnitude of the stranded cost recovery factor and
45 the impact of that factor on consumers. However, as a rough guide, I believe it
46 would be appropriate for the Commission to indicate that it expects that the
47 opportunity to recover stranded costs will expire by December 31, 2005. An outer

1 limit gives consumers a signal that the benefits of competition will not be long
2 delayed.

3
4
5 6. Paying for Stranded Costs

6
7 Q. How and who should pay for stranded costs and who, if anyone, should be
8 excluded from paying for stranded costs?

9
10 A. Stranded costs should be recovered by the utility through a separate non-bypassable
11 charge. Such costs could be assessed in dollars per kWh, dollars per kW, or dollars
12 per month. I believe that most competitive purchases of energy will be priced in
13 terms of dollars per kWh. Further, most residential and small commercial
14 consumers are metered only for kWh. Therefore, the stranded cost recovery factor
15 should be expressed in dollars per kWh. For larger commercial and industrial
16 consumers with demand meters, a dollar per kW charge could be assessed in lieu of,
17 or in combination with, a dollar per kWh charge. When suitable, dollars per kVA
18 could be used in place of dollars per kW.

19
20 Consumers subject to the stranded cost recovery charge are all (and only) consumers
21 purchasing in the competitive market. Consumers purchasing bundled standard
22 offer services during the phase-in period are already paying the full freight on the
23 utility's assets and obligations. They should not be double-charged. Consumers
24 purchasing services in the competitive market would leave the utility with no means
25 to recover stranded costs in the absence of a non-bypassable stranded cost recovery
26 charge.

27
28
29 Q. Do you have any additional comments to make concerning payment for stranded
30 costs that directly relate to distribution cooperatives?

31
32 A. The dollars recovered from a stranded cost recovery mechanism should flow to the
33 entity responsible for the debt which gives rise to the stranded costs. A careful
34 evaluation must be made to address specific circumstances between distribution
35 cooperatives and G&Ts. The situation is further affected by whether the distribution
36 cooperatives are partial requirements customers of the G&T or all-requirements
37 customers of the G&T.

38
39
40 7. True-Up Mechanism

41
42 Q. Should there be a true-up mechanism?

43
44 A. In general, yes. Customers subject to stranded cost recovery charges should know
45 those charges up-front. Therefore, the Commission should set stranded cost
46 recovery charges before they are to be imposed and should not impose them
47 retroactively.

1
2 As I indicated above, the market price of electricity in the competitive market is not
3 known. Therefore, the Commission's initial stranded cost recovery factor will be in
4 error and should be adjusted to ensure that the utilities recover the proper amount
5 of money. Further, the market price will evolve over time and the recovery factor
6 should be modified.

7
8 A true-up would not be needed if stranded cost were known for certain as would
9 occur if all strandable generation assets were sold. In some instances for
10 cooperatives, the Commission may wish to encourage a sale to avoid a subsequent
11 complex true-up process.

12
13
14 Q. How would a true-up mechanism operate?

15
16 A. I believe the stranded cost recovery factors for each utility should be reset every one
17 to two years using the most recent market price data, collections made via the
18 stranded cost recovery charge, changes in the magnitude of potentially stranded
19 costs, and other pertinent information. The Commission would conduct an
20 abbreviated hearing to set the new stranded cost recovery factors. The analyses and
21 hearing would be roughly similar to a fuel and purchased power cost adjustment
22 review.

23
24
25 8. Price Caps and Rate Freeze

26
27 Q. Should there be price caps or a rate freeze imposed as part of the development of a
28 stranded cost recovery program and, if so, how should they be calculated?

29
30 A. No. Price caps and rate freezes have been combined with the introduction of
31 competition in some states as part of a package. Development of such a package in
32 Arizona that is acceptable to many diverse parties may be time-consuming and
33 delay the introduction of competition. Further, the rate freeze would have to be
34 agreed to by each utility. Price caps would probably require full-blown rate
35 hearings unless the utilities agreed to them. We have already gone well down the
36 road to competition with the rule adopted by the Commission in 1996. Changing
37 course now would probably be counter-productive.

38
39
40 9. Mitigation of Stranded Costs

41
42 Q. What factors should be considered for mitigation of stranded costs?

43
44 A. Each utility has different opportunities to mitigate stranded costs. In general, these
45 include selling energy at wholesale or retail in other markets made available by
46 competition, sale of non-traditional services, and cost-cutting. The specific mix
47 would vary from utility to utility depending on each utility's competence, strategies,

1 and feasible opportunities. The Rules require that each utility assertively pursue
2 mitigation. A G&T cooperative should seek out mitigation alternatives and RUS has
3 a program whereby a G&T can be evaluated in the marketplace to determine what is
4 best for the consumers, lenders, and distribution owners of the G&T.

5
6
7 Conclusions
8

9 Q. Please summarize your recommendations.

10
11 A. My recommendations on each of the questions posed in the Procedural Orders are
12 presented above. I would like to highlight some of these recommendations:

- 13
- 14 • I recommend that the Commission not foreclose creative solutions to stranded
15 cost issues that could be worked out by distribution cooperatives and their
16 generation and transmission suppliers.
17
 - 18 • I recommend that the Commission encourage all distribution cooperatives and
19 G&Ts to reduce the risk of additional stranded investment exposure by avoiding
20 obstacles to restructuring all-requirements contracts that they may work out. In
21 particular, Arizona distribution cooperatives are working with G&Ts to convert
22 all-requirements contracts to partial requirements contracts. The Commission
23 should encourage this creation of opportunities to lower costs and enable
24 member-customers of distribution cooperatives to have meaningful choices
25 among electric suppliers.
26
 - 27 • I recommend that the Commission leave the current Rules as they are and retain
28 the flexibility to deal effectively and fairly with all the utility-specific features
29 that will be presented in stranded cost recovery hearings.
30
 - 31 • I recommend that the Commission give greater weight to calculations of
32 stranded cost based on the sale price of generation resources than to calculations
33 based on administrative methods.
34
 - 35 • I recommend that the market price of electricity used in administrative
36 valuations of power supply stranded costs reflect the mix of spot market
37 purchases and short, medium, and long term contracts.
38
 - 39 • I recommend that a true-up mechanism be used unless all potentially stranded
40 resources are sold or unless there are no stranded costs.
41

42
43 Q. Does this conclude your direct testimony?

44
45 A. Yes.
46

EXPERT WITNESS QUALIFICATIONS

OF

ALAN PROPPER

Mr. Propper is a veteran of the electric and gas utility industry with over 30 years' experience as an industry consultant and utility company manager specializing in the cost analysis, pricing, economics, and regulatory areas of this business. He holds the degrees of Mechanical Engineer from Stevens Institute of Technology and Master of Business Administration from San Francisco State University. He is certified as an Instructor of Engineering and Business Administration by the Arizona State Community College Certification Board. He has also completed Advanced Alternative Dispute Resolution Training and has been certified to act as a Mediator by the Northwest Regional Transmission Association and by the Western Regional Transmission Association.

In addition to holding the position of Regional Manager in Phoenix for Resource Management International, Inc. (RMI), he serves the firm as a Principal Executive Consultant whose areas of expertise include embedded and marginal cost analyses, pricing and rate design, special marketing and load management programs, State and Federal regulatory matters, contract negotiations between utilities concerning resale and wheeling services, contract negotiations between utilities and their major retail customers, and organizational training and restructuring. Mr. Propper is also a highly experienced and accomplished expert witness, having successfully testified on numerous occasions on contract provisions, pricing, and cost matters before many State and Federal regulatory agencies.

Prior to joining RMI, Mr. Propper served as Principal Consultant and Director of Consulting Services for A&C Enercom, Manager of Rate Services for Arizona Public Service Company, Supervisor of Rates for Consumers Power Company, Executive Consultant for Commonwealth Services, Forecast Engineer and Rate Engineer for Pacific Gas & Electric Company, and in Power Plant Operations for Public Service Electric & Gas Company.

Mr. Propper is recognized by his peers as an active participant in the utility industry organizations, helping to resolve many of the current regulatory, restructuring, and rate related problems facing the industry. He is an active associate member of National Rural Electric Cooperative Association. He has served on the Edison Electric Institute's Rate Committee and its Transmission Access Technical Task Force, as well as numerous other industry committees involved with training and educating utility industry personnel on today's technical and regulatory problems. He is also a member of the American Gas Association's Rate Research Committee and contributing author of their widely used text, Gas Rate Fundamentals, Fourth Edition.